IMPLICATION OF NATIONAL POLICY ON ELECTRICITY DISTRIBUTION SYSTEM PLANNING IN KENYA

BY:

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DECLARATION

Declaration by Candidate

I hereby declare that this is my own work. All alternative sources used have been identified and referenced. This thesis has not been submitted before at this or any other institution for any degree or examination.

signature removed

Mr. Michael Juma Saulo **Signature** **Date** 1st April 2010.

DEDICATION

This piece of work is dedicated to my wife Winnie and my children, Amelia, Brenda, Collins and Dorcas; you are a special source of inspiration and encouragement for hard work in my life.

ABSTRACT

The electricity distribution industry is highly capital intensive and involves investments of hundreds of millions of dollars. The developers of electricity distribution systems have to make investment decisions for an uncertain future. The investment has to meet various requirements, including flexibility, reliability and capacity for growth, and still yield an economic return. The decisions made in the planning and design stages determine how effectively these needs will be met.

Traditionally, the choice of a particular planning solution is determined by performing network analysis to assess when the power flows in a circuit or substation exceed designated capacities and then calculating the economic and financial implications associated with each possible solution. The solution that provides the optimum cost (i.e. provides the minimum economic and financial impact) would then be selected. Mitigating the electricity distribution planning problems in this manner usually ends up in under/over utilisation and unplanned development which results in high losses and costs, inadequate network capacities, poor system reliability, voltage and power quality problems etc, since the technical benefits are not given adequate considerations.

Thus this research project proposes a multi-criteria decision making (MCDM) method of electricity distribution system planning based on the Simple Multi-Attribute Rating Technique (SMART) embedded in a 'bottom-up' planning process to investigate the implication of National Policy (Kenya Vision 2030) on distribution system planning in Kenya. This approach differs from the traditional optimization approaches used in Kenya which typically assesses alternative planning solutions by finding solutions with minimum total cost. Instead a separate capital cost is calculated for each solution, this ensures that the

technical benefit of each solution is not obscured by the associated solution capital cost. By comparing the cost of each solution with the capital investment budget a most desirable solution can be determined. It is also in contrast to most utility planning procedure (e.g. Kenya Power Sector) where emphasis is on Generation and Transmission network expansions and sometimes location of substations to minimize the transmission network costs.

Specifically the approach allows for effective planning by starting the planning process from the distribution system upward. This means system requirements are worked out in upward direction, from identification of distribution network reinforcement/expansions, substation augmentations and new substations to meet distribution system requirements and transmission line development to meet substations requirements, all of which converge on the final national policy objective. The key benefit of this approach is the ability to make strategic planning decision relating to the whole distribution network and also individual planning problems, this gives an overall microscopic view of all the network problems and the planned projects within the planning horizon period, which makes it easy to prioritize projects accordingly.

In other words, it can be said that the proposed methodology seeks a solution that provides techno-economic optimization and at the same time meeting environmental criteria.

Finally, the Research project concludes by proving the validity of the hypothesis that states; 'The traditional optimization planning approaches used in electricity distribution in Kenya when subjected to a planning methodology within multiple criteria decision making technique and embedded in a 'bottom-up' planning process, allows for better decision making resulting in a more likely possibility of achieving Vision 2030 objectives'.

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ACRONYMS AND ABBREVIATIONS

AHP	:	Analytical Hierarchy Process
ARM	:	Athi-River Mining (Substation/Load point)
CEI	:	Columbia Earth Institute
ERS	:	Economic Recovery Strategy
GDP	:	Gross Domestic Product
IPPs	:	Independent Power Producers
Ken Gen	:	Kenya Generating Company Ltd
KETRACO	:	Kenya Electricity Transmission Company
KPLC	:	Kenya Power and Lighting Company
LCPDP	:	Least Cost Power Development Plan
MAUT	:	Multi-attribute Utility Theory
MAVT	:	Multi-attribute Value Theory
MCDA	:	Multi-criteria Decision Analysis
MCDM	:	Multi-criteria Decision Making
REA	:	Rural Electrification Authority
REMP	:	Rural Electrification Master Plan
SMART	:	Simple Multi Attribute Rating Technique
TANESCO	:	Tanzania Electricity Company
UETCL	:	Uganda Electricity Transmission Company Ltd.

CHAPTER 1: INTRODUCTION

1.1 Overview of the Research

The electricity distribution industry is highly capital intensive and involves investments of hundreds of millions of dollars. The developers of electricity distribution systems have to make investment decisions for an uncertain future. The investment has to meet various requirements, including flexibility, reliability and capacity for growth, and still yield an economic return. The decisions made in the planning and design stages determine how effectively these needs will be met. In the recent years three main planning assessment studies have been carried out on the Kenyan power sector with a view to improve it's effectiveness, namely;

- The "National Electrification Coverage Planning using Spatial Approach (2007)" by the Columbia Earth Institute of New York.
- The "Kenya Vision 2030" Electricity Distribution System Expansion Plan (2008) by the Kenya Vision 2030 Secretariat and,
- The "Least-Cost Power Development Plan LCPDP (2009)" done by Ministry of Energy in conjunction with the Kenya Power and Lighting Company Ltd (KPLC).

The outcome of these assessment studies in the context of this research project revealed that;

- Electricity distribution planning in Kenya is inclined towards traditional optimization approaches which typically assess alternative planning solutions by finding the solution with the minimum total cost.

- The emphasis of the power sector is mostly on expansion or scale up programmes on generation and transmission networks, subjecting distribution systems to uncontrolled expansions and unplanned developments.

The outcome of these studies significantly impact on the National Policy (Kenya Vision 2030) because the electricity distribution system infrastructure interact with economic, social and political objective of the "Kenya Vision 2030" through multiple and complex processes.

Thus this research project is intended to investigate the implication of national policy officially known as "Kenya Vision 2030" on electricity distribution system planning. This will be done through a systematic process, which will firstly involve a thorough review of electricity planning literature including the three major assessment studies carried out on the Kenyan power sector. Then, electricity distribution theory will be developed, a case study will be carried out using the existing network in coast region of Kenya as a test bed. Finally, capital costs of possible generated alternative solutions will be evaluated and compared to the capital investment budget envisaged on the vision.

The next section briefly describes the National Policy (Kenya Vision 2030) which is an integral part of this research project.

1.2 The Background of Kenya Vision 2030

Kenya Vision 2030 is the country's new development policy white paper covering the period 2008 to 2030. It aims at making Kenya a newly industrialized, *"middle income country providing high quality life for all its citizens by the year 2030"* and singles out electricity as one of the drivers of high quality life.

In this respect, the aspiration of Vision 2030 dictates that every citizen must have electricity by this time, i.e. 100% connectivity by 2030.

In the Medium Term (2008-2012), the Vision aims at increasing connectivity in the rural areas to 22% by 2012 through the adoption of the Rural Electrification Authority's (REA) Strategic Plan [REA 2007].

The Vision is based on three pillars; namely the Economic Pillar, the Social Pillar and the Political Pillar. Kenya Vision 2030 comes after the successful implementation of the Economic Recovery Strategy for Wealth and Employment Creation (ERS) which saw the country economy return to the path of rapid growth since 2002, when GDP grew at 0.6% rising to 6.1% in 2006 [Nesc, 2008].

Key components aspects of the Vision are:

A. Economic Aspirations

Under Vision 2030 Kenya's economic vision and strategy is to increase annual GDP growth rate to 10% and maintain that average until 2030 (to be revised periodically).

Nesc [2007] reports that;

> *"Delivering the country's growth aspirations will require a rise of national saving from gaining about 17% in 2006 to about 30% in 2012,it will also be necessary to deal with significant informal economy employing 75% of the country's workers. Formalizing productivity and distribution will increase jobs, incomes and public revenues, other critical problem include poor infrastructure and high energy cost"*

According to the Vision 2030 Secretariat report [2008], six key sectors outlined below have been given priority in acting as key growth drivers in the journey to 2030 economic growth;

- Tourism
- Agriculture
- wholesale and retail trade
- Manufacturing
- Business Process Off shoring (BPO)
- Financial

All these key growth drivers of the economy according to [McDonald 1994] require an efficient and reliable electricity distribution system. This means that the electricity distribution network must be able to;

- Cover the service territory reaching all customers
- Have sufficient capacity to meet the peak demand of it's customers
- Provide highly reliable delivery to its customers for efficient production
- Provide stable voltage quality to its customers for maximum productivity

B. Social Aspirations

Kenya's journey towards prosperity also involves the building of a just and cohesive society, which enjoys equitable social development in a clean and secure environment. This quest is the basis of transformation in eight key social sectors;

- Education and Training
- Health
- Sanitation
- Environment
- Housing and Urbanization

- Gender, Youth Sports and Culture
- Equity and Poverty Reduction.
- Kenyans with various disabilities and previously marginalized communities.

These policies (and those in the economic pillar) will be founded on all-round adoption of Science, Technology and Innovation (STI).

Bouille et al [2003] notes that the transition from a self sufficient agricultural economy (e.g. The Kenyan economy) to a more urban economy requires capital and foreign exchange. Electricity is an important factor in this process, fuelling urbanization and other social sectors of an economy, its industrial growth and rising standard of living.

C. Political Aspirations

The political system should be issue-based, people centred, results oriented and an accountable democratic system. Kenya will adopt a democratic decentralization process with substantial devolution in policy-making, public resource management and revenue sharing through selected devolved funds [Nesc, 2008].

The National Policy dubbed "Kenya Vision 2030" is first geared towards transforming the lives of Kenyans socially, economically and politically. A number of research papers show that access to safe and reliable electricity distribution network is one of the keys to economic and social development [Wamukonya 2003; Bouille et al 2003; Gaunt 2003].

Secondly this is illustrated by the international community's adoption of the rate of electrification as one of the indicators of a country's overall development [World Bank, 2001]. These two attributes have led to the conception of this research project.

1.3 Research Hypothesis

The basic hypothesis that this thesis addresses is:

An empirical assessment of traditional optimization planning approaches used in electricity distribution system in Kenya when subjected to a planning methodology within multiple criteria decision making techniques embedded in a "bottom-up" planning process, allows for better decision making, resulting in a more likely possibility of achieving the "Kenya Vision 2030" objectives.

The research questions that are posed below are meant to lead us to preliminary answers that will eventually be considered when testing the validity of the hypothesis.

1.3.1 Research Questions

- Which methods/approaches of electricity distribution system planning are currently being used in Kenya and how effective are they with regard to Kenya Vision 2030 objectives?
- Which planning method or approach is compatible and viable for electricity distribution system in Kenya? And how can it be modelled for applicability in achieving the "Kenya Vision 2030" objectives?

1.4 Research Methodology

Research is an organized and systematic way of finding answers to questions. In this research project substantial quantity of data is available, and as it is sorted and interpreted to answer the research questions, it is expected to give insight to the basic hypothesis.

Answering the research questions and eventually testing the validity of the hypothesis will involve the following research methodologies;

- Evaluating and analyzing the outcomes of the recent assessment studies carried out on the power sector in Kenya to assess their implication on the Kenyan Electricity Distribution System.
- Conducting an investigation/survey from published literature on techniques, methods and approaches used for electricity distribution system planning with an aim of identifying changes or adjustments that may be made to ensure they are compatible with the 'Kenya Vision 2030' objectives.
- Carry out a case study of electricity distribution system planning on an existing distribution network in the coastal region of Kenya.

Data Collection requirements:

- Acquire and study the "update of the Least Cost Power Development Plan 2008-2028 and 2009-2029 final reports" to establish how they addresses distribution system planning in Kenya.
- Acquire and study the rural electrification master plan and the Rural Electrification Authority (REA) Strategic Plan 2008-2012.
- Study the Kenya Power and Lighting Company (KPLC) and other utilities electricity distribution planning approaches.

- Study the Vision 2030 secretarial delivery report and other relevant Government policy papers.
- Study the Kenya Electrification Master Plan
- Study The Kenya National Electrification Coverage plan by Columbia Earth Institute.

1.5 Rationale of the Research

The basic objective of an electricity distribution system is to provide electricity in a sustainable manner i.e. economically, financially, socially, politically and environmentally. This implies availability of resources, universal access to the service, consumer satisfaction with quality, and meeting equity and environmental constraints [Wamukonya, 2003].

It is fairly settled in this chapter that electricity distribution system infrastructure plays a critical and positive role in social and economic development. The infrastructure interacts with economical, social and political objectives of the "Kenya Vision 2030" through multiple and complex processes. Therefore it is important to investigate the effects of the traditional optimization approaches currently being used for electricity distribution system planning in Kenya and evaluate their merit and demerits. Secondly assess the impact of these approaches when subjected to a planning methodology within multiple criteria decision making techniques (MCDM) embedded in a "bottom-up" planning process to evaluate their implication in terms of viability, better decision making and resource allocation.

1.6 Structure of the Thesis

The Structure of this thesis is determined by the objectives of the research and the processes needed to test the hypothesis. The various chapters are described briefly below, to put the work in the context as each section of the research is being developed.

Chapter one: Provides the overview of the thesis, gives background information on 'Kenya Vision 2030', defines the hypothesis. Presents the research question and methodologies to be used to answer the research question and to test the validity of the hypothesis and finally concludes by justifying the rationale behind the research.

Chapter two: Reviews the three assessment studies on the Kenyan power sector and published literature on electricity distribution system planning with a view of answering the research question in chapter one.

Chapter three: Develops the theory of electricity distribution system planning in the context of this research project.

Chapter four: Describes and analyzes a case study of an existing distribution network in the Coastal region of Kenya using an MCDM technique.

Chapter five: Analyses and evaluates distribution costing of possible alternative solutions configured in the case study and compares them to the capital budget envisaged in the "Kenya Vision 2030"

Chapter six: This is the concluding chapter and uses the outcome of the research project to prove the validity of the hypothesis and gives recommendations.

1.7 Onward

No one today is ignorant of the part played by energy particularly electrical energy, not only in science, but in industry, politics and the whole science of human welfare.

From cradle to the grave, everyone is dependent on nature for absolutely continuous supply of energy in one or other of its numerous forms. When energy supplies are ample there is prosperity, expansion and development. When there are not there is want. Often it has been found to be true, that energy plays a very subsidiary and indirect part of development, just as no doubt, the supply of wind might be looked upon as playing a very secondary role in the music organ. The fact remains if the supply of energy failed, modern civilization would come to an end as abruptly as does the music of an organ deprived of wind [McDonald, 1994].

Therefore to ensure ample supply of energy in future proper planning of the energy resources has to commence now.

In Kenya rapid load growth is projected, therefore electricity distribution system planning must be analyzed and evaluated carefully to determine the effect of various delivery options on the overall operating cost of the system. The options chosen should minimize the present worth of operating and capital expenses while meeting safety, reliability and environmental criteria.

The next chapter describes the published literature on Electricity Distribution Planning approaches/methods, starting by evaluating the three recent assessment studies carried out on the Kenyan power sector.

CHAPTER TWO: LITERATURE REVIEW

2.1 Introduction

The people responsible for planning, designing, implementing and operating large capital intensive electricity networks that affect most productive facilities in the country and the quality of life of the inhabitant are electrical engineers. Most of the training and work habits of these engineers are based on a problem-solving approach using technological principles that have matured over the hundred-year life of the electricity industry. However in many cases, the people involved in the problem solving, financial and political decision making activities that support the investment have very little understanding of the overall objective being pursued [Martinot, 2003, Gaunt, 2003].

Electricity distribution system planning is a very complex decision problem for at least two different reasons; firstly is the multiplicity of criteria of a very different nature (economic, technical, environmental, social etc) involved in the process, and secondly is the manner in which different segments of society or stakeholders perceive these criteria (see appendix B).

Linares and Romero [2002] note that electricity distribution system planning is considered a decision-making problem with several criteria and different decision makers (stakeholders) are involved. In this chapter the literature survey is directed to:

- Investigating the outcome of the three major assessment studies carried out on the Kenyan power sector with respect to Electricity Distribution System Planning from the African context perspective.
- Investigating from the published literature the electricity distribution system planning approaches/methods that may be compatible, viable and applicable to the existing distribution system in Kenya with reference to "Vision 2030" objectives

All these activities are carried out with a view of answering the research question addressed in section 1.3.1 and will finally be used as aid in the testing of the validity of the hypothesis.

2.2 Assessment studies on the Kenyan Power sector with regard to Electricity Distribution System Planning

In Kenya the traditional utility planning procedure has been primarily based on a 'top down' approach, where future system developments are determined from the overall system requirements [LCPDP, 2007]. In the case of the power utilities, emphasis has been on generation, transmission and the location of substations to minimize the transmission network costs [LCPDP, 2009].

Distribution networks in Kenya have usually been subjected to uncontrolled expansions, under/over utilization and unplanned development. As a result many problems can be seen in the distribution networks such as high power losses, inadequate network capacity, poor system reliability, frequent power outages, voltage and power quality problems etc [REA 2007, Willis and Scott 2000].

The Kenya electricity distribution system is currently operated and maintained by the Kenya Power and Lighting Company (KPLC) and the Rural Electrification Authority (REA).

The former is a profit driven Government parastatal with the mandate to purchase bulk electricity supply, transmit, distribute and retail electricity to the end use customer throughout Kenya. In the course of carrying out its mandate the company ensures it's expansion projects and programmes are reflective of infrastructural developments for the electricity sub-sector as envisaged in the Government economic policy and national development objectives. The later is a Government agency with a specific mandate to speed up the implementation of Rural Electrification (distribution), section 67 of the Energy Act No 12 of 2006 [MOE, 2007].

Figure 2.1 illustrates in detail the Kenya power sector structure and the inter-relationship.

The two organizations mentioned above have different goals when it comes to planning of the electrical distribution system .As a result different planning approaches/models have been used in their planning endeavours with regard to their specific mandates assigned to them by the ministry of energy in the Kenya government.

The next section looks at the outcome of the three major assessment studies on the Kenyan power sector with respect to distribution planning approaches. They are listed as follows:

- The Least Cost Power Development Plan/Approach [2009].
- The "Kenya Vision 2030" Electricity Distribution Expansion Plan/Approach [2008].
- National Electrification Coverage Planning using Spatial Approach [2007].

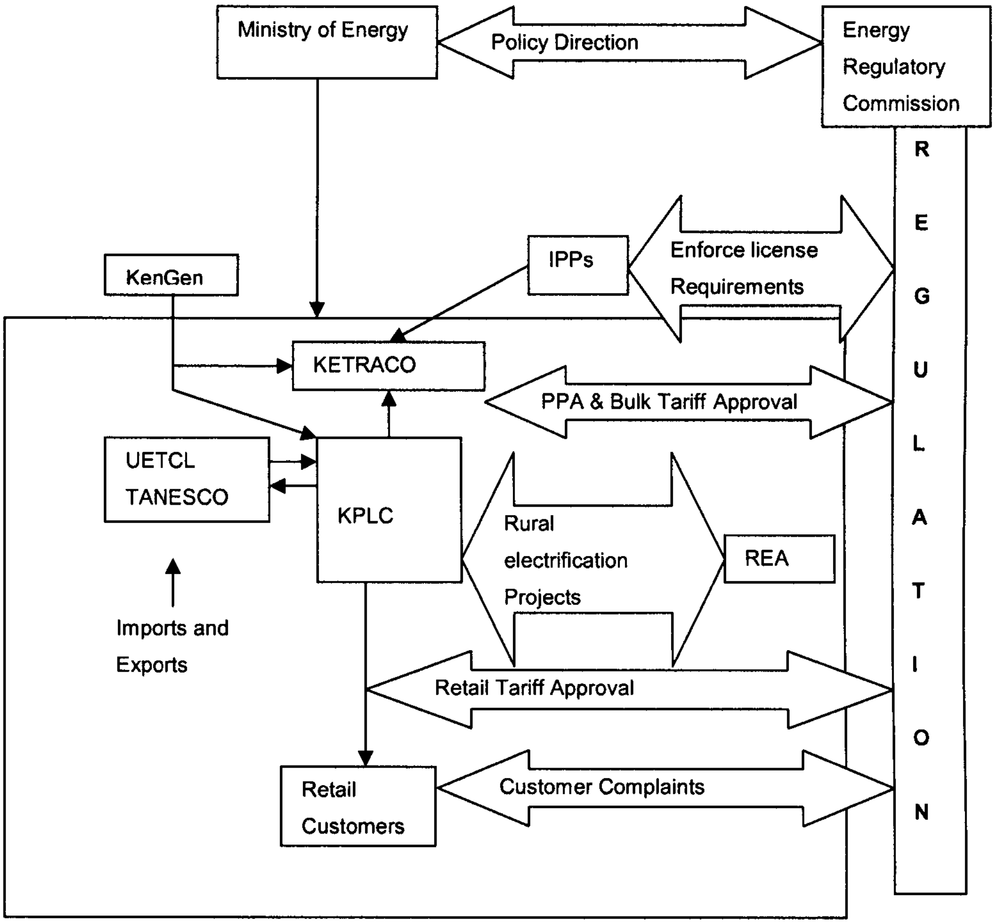

Figure 2.1 Power sector structure [Source: Vision 2030 Secretariat 2008]

2.2.1 The "Kenya Vision 2030" Electricity Distribution Expansion Plan.

The Vision 2030 electricity distribution expansion plan was developed in May 2008 by the Vision Secretariat in conjunction with the Kenya Power and Lighting Company and the Ministry of Energy Electrical Personnel. The objective of the "Kenya Vision 2030 Electricity Distribution Expansion Plan" according to the Vision Secretariat Report [2008] was to expand the National Power Distribution Grid under the Energy Access Scale-up Project.

This entails connecting 1 million new customers spread country wide over the next five year medium term plan period (2008-2012). In addition to new customer connections, the new distribution projects were to serve the objectives of system loss reduction, power supply quality improvement and automation enhancement.

The envisaged strategy for the expansion plan was the construction of an additional approximate 16000kMs of MV distribution lines, 1,000MVA of distribution substations, 50,000kms of LV distribution lines, 3,000MVA of distribution transformers and 1 million service lines [Vision 2030 Secretariat Report, 2009].

The project was supposed to cover the following key areas:

(i) Upgrade of the existing and construction of new substations;

(ii) Reinforcement and extension of the distribution network;

(iii)Upgrade of Supervisory Control and Data Acquisition/Energy Management System (SCADA/EMS).

(iv)New distribution lines and substations to be initiated to further extend power supply in rural areas.

These projects were to be developed by Kenya Power and Lighting Company (KPLC) and Rural Electrification Authority (REA) with construction work to be shared between KPLC, Turnkey Contractors and labour and transport contractors [LCPDP 2009].

2.2.2 Spatial Approach to Electricity Distribution Planning

The spatial planning approach is an approach that took a long term nation-wide view of electricity needs across the sectors of the National Economy.

According to the Columbia Earth Institute (CIE) report [2007], the main innovation of the method was the incorporation of detailed spatial information, particularly population distribution with projected demand, when developing a national plan for electricity distribution.

Spatial data is used to better characterize the total area over which it was cost- effective to extend the grid to improve the estimation of total cost of grid roll out, and to plan for upgrades based on how new branches of the grid are to be connected to the existing backbone.

Modi et al [2006] says that a spatial approach improves the identification of the most cost effective opportunities for rapid expansion and simplifies short term planning which may be constrained by particular national or regional priorities given long term goals. Using a spatial algorithm, the approach considers which available technologies e.g. grid, solar PV, diesel mini-grid are more appropriate, given projected demand, costs and location.

This approach guided the development of the Earth Institute (EI) Electricity Planning and Investment Costing Model. The model was used to carry out national electrification coverage planning in Kenya. It is an interlinked Excel-GIS-Java tool running from an excel interface, with many GIS-based pre-and post processing options. The tool provides reasonable cost estimates that can be rapidly fed into planning and financing documents [CIE, 2007].

According to the CIE report [2007] the model also has the ability to create multiple 'what- if' scenarios and easily tests sensitivity to demand and other assumptions, providing decision-support for policy makers evaluating rural electrification scenarios and costs. The EI model involves several analytical steps that respond to the following basic questions

- Where is the grid currently?
- Where is the demand of electricity and how is it distributed?
- How much will each technology cost in each location?
- What is the least-cost scale up plan in the long run?
- How should connection be prioritized in the short-term?
- What is the total cost of the investment?
- How much additional demand will this add to the current distribution network?

The primary focus of the assessment study carried out by the Columbia Earth Institute [2007] using the spatial approach on the national electrification coverage planning in Kenya was increased connections and extension of the distribution grid. The EI approach dealt with national scale-up including households and institutions, focusing on the most cost–effective connections and technologies regardless of political administrative boundaries.

2.2.3 The Least Cost Power Development Plan/Approach

The least cost 2009-2029 update of the Least Cost Power Development Plan (LCPDP) report 2009 is subsequent to the 2008-2028 LCPDP report prepared by the KPLC, in consultation with the Ministry of Energy in 2007. Power demand forecast was revised to capture the event of the recent pertinent developments, which include accelerated customer growth and the country's economic vision dubbed "Kenya Vision 2030" [LCPDP, 2009]. The report focused on scaling up generation and transmission and also projecting annual increases in system peak demand based on growth in energy demand resulting from GDP growth as well as new connections.

The LCPDP report [2009] projected an increase in energy demand from both economic growth and 200,000 new connections per year over the next five years up from the previous projection of 120,000 new connections in the previous LCPDP update of 2007, including households and other connections, based on an enhanced customer connection campaign programme and an intensive Rural Electrification Programme.

In 2007, the Ministry of Energy produced a prospectus for required upgrades to the generation, transmission, and distribution systems in Kenya, and estimated their cost. Assumptions for the number of new connections, household energy consumption, and costs made in these two reports differ from one another as well as from the assumptions made in the current Rural Electrification Master Plan (REM) 2009 update.

The Ministry of Energy 2007 prospectus focused on extensions to rural markets, public institutions & facilities and industries, allocating new connections based on first distributing connections to each province in proportion to population, and then dividing up each province's allocation equally among its constituencies [MOE 2007].On the other hand the LCPDP report [2009] and the Rural Electrification Master Plan [2009] were more concerned with energy access scale up programmes to be implemented targeting one million new households to be connected to the national grid over the next five years at a cost of approximately US$1.46 billion.

2.2.4 Summary of Electricity Distribution Planning Approaches in Kenya

The above discussed three assessments studies on the Kenyan power sector show that electricity distribution planning in Kenya is inclined towards traditional planning optimization approaches which usually include a single criteria or objective only in the planning procedure. This criteria is commonly minimization of cost or line losses when carrying out expansion plans or scale-up programmes [Alarcon et al [2006]. These three planning assessment studies seem to have given least- cost capital criteria a higher priority than any other criteria associated with electricity distribution planning which are just as important.

Willis [1997] says that the objective of distribution planning is to provide an orderly and economic expansion of equipment and facilities to meet the electric utility's future electrical demand with an acceptable level of reliability. This shows that apart from the least capital cost criteria other pertinent issues such as capacity constraints, system reliability, power quality, environmental impact etc need to be seriously considered.

Alarcon et al [2007] adds that an Electricity Distribution System Planning approach that only considers one criterion will be solving only one part of the problem. In contrast to a multiple criteria technique which has many advantages including examining and assessing the trade–offs between different alternative solutions, resulting in a more informed decision.

The following is the specific evaluation and outcome results of the three assessment studies carried out on the Kenyan power sector;

Kenya Vision 2030 Electricity Distribution Expansion Plan/Approach

The first planning approach i.e. the "Kenya Vision 2030 Electricity Distribution Expansion Plan/Approach" which had a large percentage of its content drawn from the Rural Electrification Master Plan of 2009 was focused on energy access scale up or expansion projects with main emphasis on electricity distribution project plans with minimum capital cost and system loss reduction. Although it mentioned improving power quality and enhancing automation it did not explain how this may be achieved.

This planning approach is similar to "integrated development planning" where cooperation between the many sectors being integrated is required. In such cases lenders and donors may impose conditions requiring integration of electricity distribution system projects with other development programmes. This could be based on a belief that the increase in benefit exceeds the cost of integration, or it could be required to help those agencies present their aid programmes to supporters with other objectives. In practice, the formal integration of plans and programmes also requires greater political participation, sometimes perceived as political interference [Gaunt, 2003].

Integration is a characteristic of the log frame. If the participants understand the desired impact of the electricity distribution planning and the processes or linkages needed to reach the desired outcomes, and then the need for central integration or co-operation will be much smaller. Having a better understanding of development helps planners in each discipline to make better judgments and fewer expensive mistakes.

The National Electrification Coverage Plan/Approach

The Second assessment study i.e. "The national electrification coverage planning for investment costing estimating model using spatial approach" was carried out by the Columbia Earth Institute with input from the Kenya Power and Lighting Company (KPLC). This report used the spatial methodology which resulted in electrifying an additional 1,078 million households over the next five years i.e. (2008-2012), raising Kenya's national electrification rate from 15% to approximately 22%. It found out that the most cost-effective technology was a grid connection since 94% of households in Kenya were within the grid compatible area. The 1,023 million new grid connections covered by this scale-up plan would require 991MW of additional peak power supply, excluding the impact of economic growth on energy demand beyond that of productive demand assumed in the model [CEI, 2007].

According to LCPDP report [2007] an estimated 63% of Kenya's population of 36million lived in sub locations served by existing 33 kV and 11 kV distribution lines. However, the penetration rate (defined as the percentage of households with a grid connection) remains low, approximately 30% in high-density urban areas and 10% in other areas. This planning method may be likened to "Selective electricity distribution planning" where much effort is directed to identifying objective criteria for priority ranking of communities according to distance from the existing network, settlement density, potential for economic activity, public facilities and other parameters.

Gaunt [2003] argues that there will always be political lobbying in a social or socio-economic programme of electrification from a distribution and an African continent context

2.3 Overview of the Planning Process

Regardless of what or why something is being planned, there are certain common aspects to all planning and certain functions inherent in all planning [Willis, 1997]. An important aspect of effective planning is analysis of uncertainty in future events and planning for their possibility. Planning is normally a decision-making process that seeks to identify the available options and determine which is best. Applied to electric utility planning, the process seeks to identify the best schedule of future resources and actions to achieve the utility goal [Willis, 1997 and Gonen, 2000].

Willis and Scott [2000] say that planning is the process of identifying alternatives and selecting the best from among them. The planning process can be segmented into five steps as shown in Figure 2.2.

Each step is an important part of the process of accomplishing the goals of any type of planning, particularly electricity distribution system planning. Any of the five steps poorly performed, will lead to poor decision making, a poor plan and ultimately failure to attain those goals [Willis, 1997].

The approach in figure 2.2 is normally a general approach that can be used in many fields e.g. engineering, management, business, computing etc.

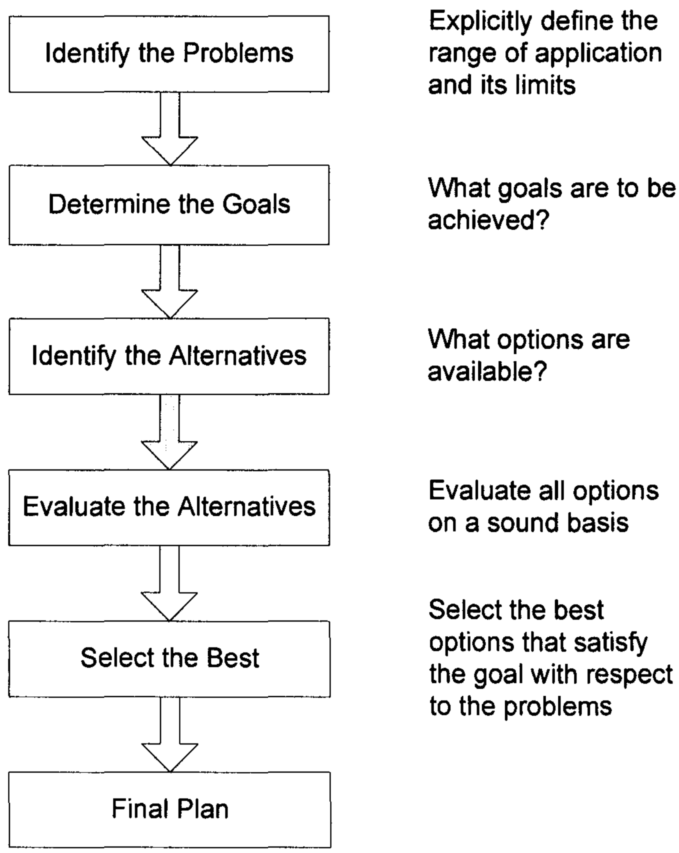

Figure 2. 2 The General Planning Process [Source: Willis, 1997].

2.3.1 Bottom–up Distribution Planning Process

Traditionally, utility planning procedures were based on a "top-down" approach whereby future system developments were determined from an overall system requirement. In case of power utilities, emphasis was on generation and transmission network and sometimes location of substations to minimize transmission costs.

According to Willis and Scott [2000], distribution networks have always been subjected to uncontrolled expansions, under/over utilization and unplanned development. As a result many problems can be seen in the distribution networks in many utilities. These include high losses, inadequate network capacity, poor system reliability, voltage and power quality problems etc.

Distribution networks extend to every geographic location covered by the utility providing final connection between the utility and the customer. They are therefore considered the most suitable system to capture localized customer requirements, load demand and growth patterns etc. For example, demand growth will be different in different areas; certain areas need high supply reliability etc. Effective planning process therefore begins from distribution system. System requirements are then worked out in upward direction, from identification of distribution network reinforcements/expansions, substation augmentation and new substation to meet this distribution system requirements, and transmission line development to meet substation requirements, all of which converging on final objectives; meeting the customer needs and techno-economic optimization. This is known as the "bottom-up" approach in utility planning [ADEA, 2008]. In modern utility approach; this process is carried out through computer aided network modelling and analysis tools.

2.3.2 Electricity Distribution Planning Models/Approaches

So far, as Electricity Distribution System planning is concerned, optimization methods used may be divided into approaches and models. There is however a special case of planning method that is applicable to reinforcement planning. Network planning approaches may be classified as ranging between Judgmental and Mathematical [Wang and McDonald, 1997].

Judgmental (Heuristic) approaches are scientific methods that use mathematical evaluation but allow planners discretion to reach planning solutions while mathematical approaches on the other hand only use comprehensive mathematical analysis techniques to reach a decision. According to Vaziri et al [2000] network planning may be further broadly divided into *static* (single stage) and *dynamic* (multi stage) network planning.

Static Network Planning is interested in the network connection schemes for a particular future load horizon year and does not consider the transit problem of network connection schemes, as such is called horizon year planning.

Dynamic Network Planning is a long term or a longer planning period divided into several horizon years in which the transit problem of each horizon years is considered, one has to decide when and where to build a new line.

Today's electricity industry requires planning tools that are flexible and adoptable therefore planners should be able to choose the attributes, objectives and constraints to consider and also the importance of one objective in relation to others [Alarcon et al 2007 and Vaziri, 2000].

Celli et al [2005] notes that the inclusion of different objectives may produce different optimal plans; but this can be very useful when the planning environment is as dynamic as in today's electrical distribution industry.

2.3.3 Evolution of the Network Planning Approaches/Models

Electricity distribution planning has evolved from simplistic to complex planning models as shown in Figure 2.3. Planning is a complex task such that no generalization could be made in the application of specific model without loss of accuracy [Vaziri et al 2000].

Over the last four decades, network planning researchers established a variety of planning methods from simplified models to the multiple criteria planning methods. According to Krishans et al [1997] these techniques have evolved and benefited from development in scientific knowledge and computational capacities or tools.

Figure 2.3 shows that by 1997 network planning models had already evolved to multiple criteria planning models. This is also confirmed by [Alarcon et al 2007, Haesen et al 2006, Espie et al 2003 and 2005, and Neimane, 2001],who show that electricity distribution planning can be formulated as a multiple criteria problem. The next section describes the multi-criteria decision making techniques.

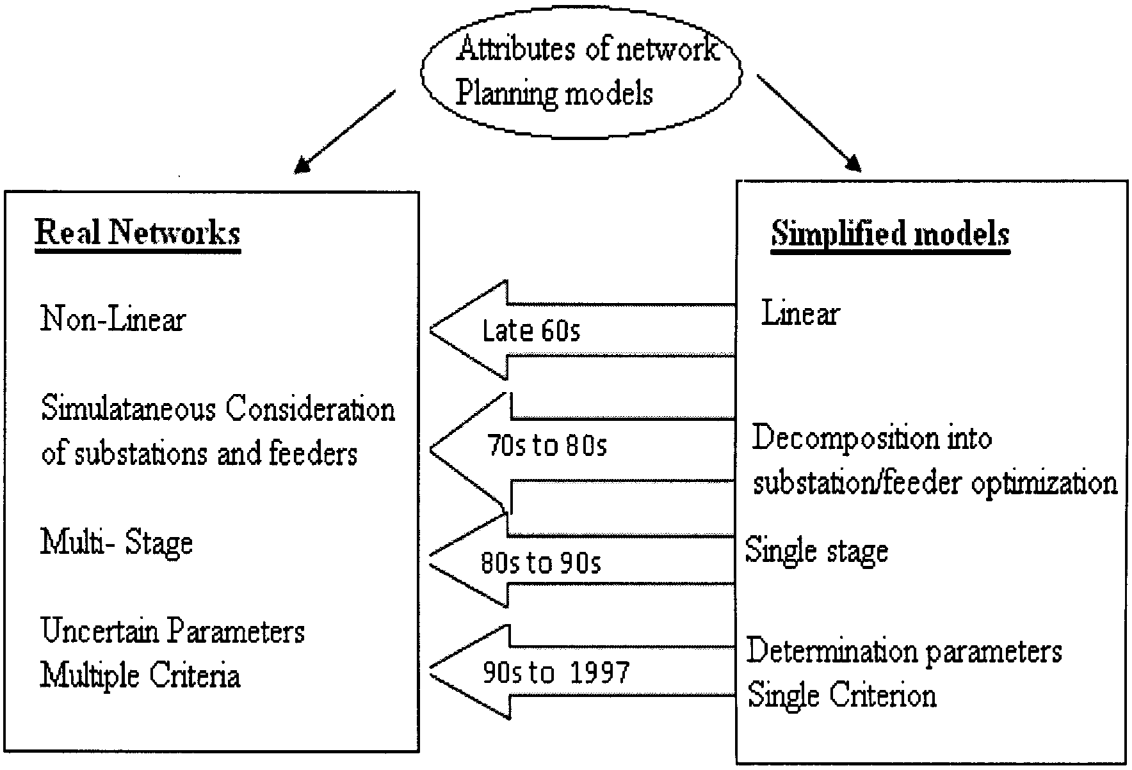

Figure 2.3 Attribute of Networking Planning Models [Source: Krishna et al, 1997]

2.4 Overview of Multi-criteria Decision Making (MCDM) Methods

Multi-Criteria Decision Making is a well known branch of decision making. It is a branch of a general class of operations research models which deals with decision problems under the presence of a number of decision criteria [Pohekar and Ramachandran, 2003].

Loken [2005] states that MCDM is a generic term for all methods that exist for helping people making decisions according to their preferences, in cases where there is more than one conflicting criterion.Using MCDM can be said to be a way of dealing with complex problems by breaking the problem into smaller pieces. After weighting some considerations and making judgments about smaller components, the pieces are then reassembled to present an overall picture to the decision makers.

The MCDM models are divided into Multi-objective Decision Making (MODM) and Multi-attribute Decision Making (MADM) [Pohekar and Ramachandran, 2003]. There are several methods in the above categories. Priority based, out ranking, distance based, and mixed methods are also applied to various problems. Each problem has its own characteristic.

According to Neimane [2001] the methods can be classified as deterministic, stochastic and fuzzy methods. Depending upon the number of decision makers, the method can be classified as single or group decision making method. Decision making under uncertainty and decision support systems are also prominent decisions making techniques.

These methodologies share common characteristics such as;

- Conflict among criteria
- Incomparable units
- Difficulties in selection of alternatives.

In multiple objective decision making, the alternatives are not predetermined but instead a set of objective functions is optimized subject to a set of constraints. The most satisfactory and efficient solution is then sought.

In this identified efficient solution it is not possible to improve the performance of any objective without degrading the performance of at least one other objective. In multiple attribute decision making, a small number of alternatives are to be evaluated against a set of attributes which are often hard to quantify. The best alternative is usually selected by making comparisons between alternatives with respect to each attribute. The multi-criteria decision process is shown in Figure 2.4

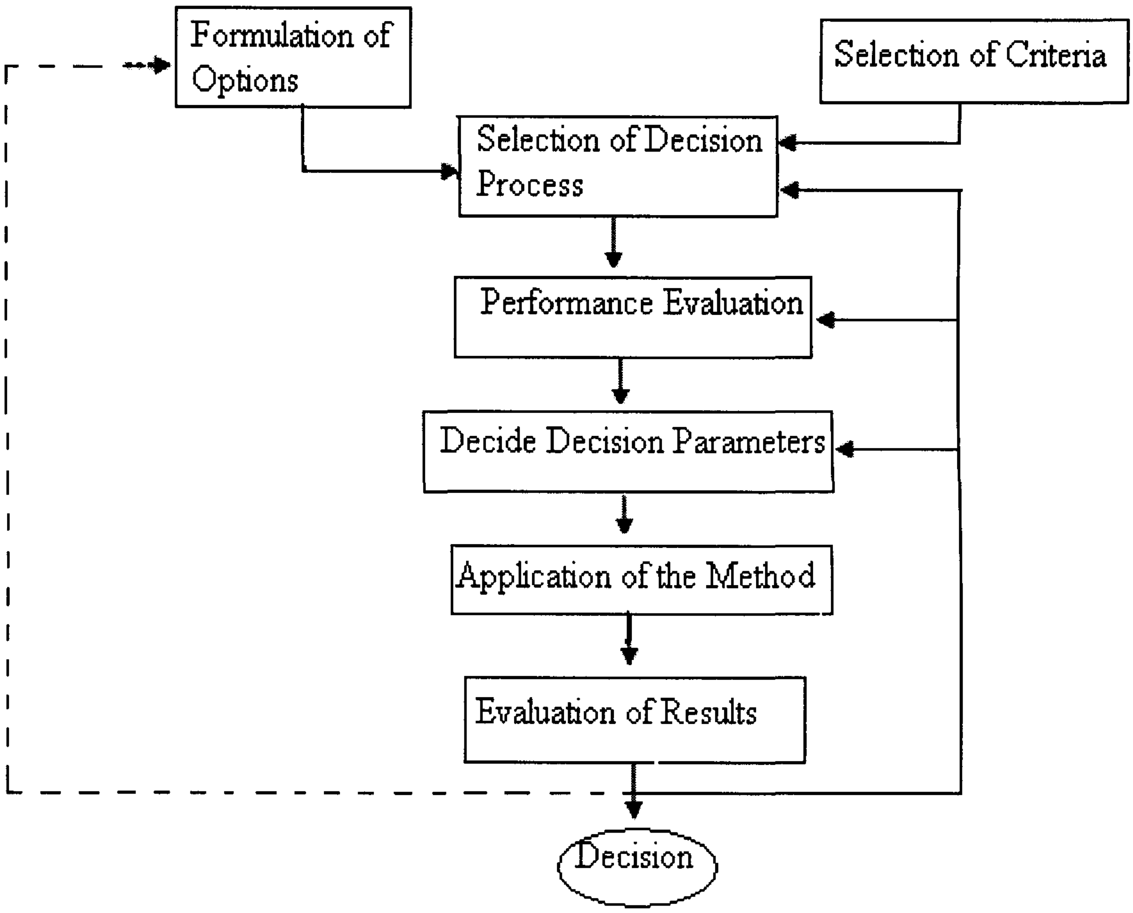

Figure 2.4 Multi-criteria decision processes [Pohekar and Ramachandran, 2003].

Belton and Stewart [2002]. states that owing to the fact that the MCDM methods themselves can not make decision but aids the Decision Makers, to make decision then, 'decision analysis' or 'decision aid' may be used instead of 'decision making' hence Multi-criteria Decision Making (MCDM) is converted to Multi-criteria Decision Analysis (MCDA).

2.4.1 Multi-criteria Decision Analysis

Over the years, hundreds of MCDA methods have been proposed, the methods differ in many areas – theoretical background, type of question asked, and type of results given [Loken, 2005]. Some methods have been created particularly for one specific problem, and are not useful for other problems. Other methods are more universal, and many of them have attained popularity in various areas. The main idea for all methods were to create a more formalized and better informed decision making process [Hobbs and Horns, 1997].

2.4.2 Choosing an MCDA Method

When choosing an MCDA method, there are many criteria to consider. The aim is to find a method that measures what it is supposed to measure (Validity).Different methods are likely to give different results, so the method that reflects the users "true value" in the best possible way should be chosen. In addition the method should provide the Decision Makers with all the information they need and the method must be compatible with accessible data (appropriateness).The method must also be easy to use and easy to understand [Hobbs and Horn, 1997].

If the Decision Makers do not understand what is happening inside the methodology, they perceive the methodology like a black box. The results may be that the Decision Makers may not trust in the recommendations from the method. In that case, it is meaningless to spend time applying this method.

2.4.3 Classifying MCDA Methods

There are many possible ways to classify the existing MCDA methods. For this research project I have chosen the Belton and Stewart [2002] method of classification since it corresponds closely to the electrical power system expansion planning. According to their classification there are three broad categories (or school of thought):

- Goal, aspiration and reference level models
- Outranking models (the French school)
- Value measurement models

This research project is based on the Value measurement models whose characteristics will be described in detail. The other two methods are briefly explained to give the reader an overall view of the MCDA models.

Goal, aspiration and reference level models

According to Belton and Stewart [2002], usually the Goal Programming (GP) is used as a common abbreviation for all these approaches. When using GP approaches, we try to determine the alternatives that in some sense are the closest to achieve a determined goal or aspiration level. Often the GP approach is used as a first phase of a multi-criteria process where there are many alternatives. In that case, it is used to filter out the most unsuitable alternatives in an efficient way. Mathematically, we can say that the idea in the GP method is to solve the inequality

$z_i + \delta_i \geq g_i$, Where z_i, is the attribute values, δ_i is the non-negative deviational variables and g_i is the goals (a desirable level of performance) for each criterion *i*. The aim is to find a feasible solution that where $\delta_i = 0$ for all *i*, this will be the recommended solution.

In most cases, this is not the case, and another solution must be found. The simplest method for this purpose is to minimize the weighted sums of deviations

$$\sum_{i=1}^{m} W_i \, \delta_i \qquad (2.1)$$

where W_i is the importance weight and δ_i is the deviation of the criteria i.

Outranking Models (The French School)

In outranking models, the alternatives are compared pair-wise to check which of them is preferred regarding each criterion. When aggregating the preference information for all the relevant criteria, the model determines to what extent one of the alternatives can be said to outrank another. We can say alternative *a* outranks an alternative *b* if there is enough evidence to conclude that *a* is at least as good as *b* when taking all criteria into account [Loken, 2005]

The methods based in this way of thinking are often called the French school. The two main families of methods in the French School are ELECTRE (Elimination and Choice Translating Reality) and PROMETHEE (Preferences Ranking Organization Method for Enrichment Evaluation).

2.4.4 Value Measurement Models

When using value measurement methods, a numerical score (value) V is assigned to each alternative. These scores produce a preference order for the alternatives such that *a* is preferred to b $(a > b)$ if and only if $V(a) > V(b)$.When using this approach ,the various criteria are given weights *w* that represents their partial contribution to the overall score, based on how important this criterion is for the DM(s).Ideally ,the weight should indicate how much the DM is willing to accept in the trade off between two criteria [Belton and Stewart, 2002,Wang and McDonald 1994].

The most commonly used approach is an additive value function (Multi-attribute Value Theory MAVT):

$$V(a) = \sum_{i=1}^{m} W_i V_i(a) \qquad \textbf{(2.2)}$$

Where $v_i(a)$ is a partial value function reflecting alternatives a's performance

on criterion i.

The partial value function must be normalized to some convenient scale (e.g.0-100).

Using Eq (2.2), a total value score V (a) is found for each alternative a. The alternative with the highest value score is preferred. MAVT is pretty simple and user friendly approach where the Decision Makers in cooperation with analyst only needs to specify value functions and define weights for the criteria to get very useful help with his decision [Belton and Stewart, 2002].

The Multi-attribute Utility Theory (MAUT) can be said to be an extension of MAVT.

MAUT is a more rigorous methodology for incorporating risk preference and uncertainty into multi-criteria decision support methods .When using this approach, multi-attribute utility functions $U(a)$ where the risk preferences are directly reflected in the values – must be established instead of value functions [Loken, 2005].

The Analytical Hierarchy Process (AHP) developed has many similarities to the multi-attribute value function approach.

Belton and Stewart [2002] described AHP "as an alternative means of eliciting a value function", however, they pointed out that the two methods rest on different assumptions on value measurements, and that AHP is developed independently of other decision theories.
Of these reasons, many of the proponents of AHP claim that AHP is not a value function method. However both MAUT and AHP present their results as cardinal rankings, which mean that each alternative is given a numerical desirability score. Consequently, the results from the two methods are directly comparable.

The major characteristic of the AHP method is the use of pair-wise comparisons, which are used both to compare the alternatives with respect to the various criteria and to estimate criteria weights. In the pair-wise comparison, a special ratio scale is shown in Table 2.1.

Table 2.1 Intensity of Preference table [Source: Saaty 1996]

Fundamental Values	**Intensity of Preference**
1	Equally Preferred
3	Weak Preference
5	Strong Preference
7	Very Strong or Demonstrated Preference
9	Extreme Importance
2,4,6,8	Intermediate Values

The results from all the comparison are put into matrices. From these matrices an overall ranking of the alternatives can be aggregated. The alternative with highest overall ranking is preferred to the others [Saaty 1996].

These three categories find application in different natures of energy/electrical planning problems, apart from the superiority of one model over the other in solving particular problems, the accuracy of information and its availability plays a very vital role in the MCDA modelling techniques. The next section looks at the MCDA/MCDM from the electricity distribution system planning perspective.

2.5 Application of MCDM in Electricity Distribution Planning

In today's electricity distribution system planning demanding issues such as distributed generation, demand side management, quality of supply, societal impacts and environmental implications are now becoming as important as load growth and must also be included in the planning activity [Alarcon et al 2007,Espie et al, 2005].

However, the inclusion of such issues in the planning process using traditional techniques would require many of these factors to be converted to an equivalent cost, which may prove difficult since they are not naturally cost variables.

A logical solution is to consider techniques which are explicitly designed to deal with multiple criteria. Previous work shows that electricity delivery planning can be formulated as a Multiple Criteria Problem [Miranda et al 1998, Wang and McDonald 1994, Espie et al 2003, and Loken 2005].

There are basically two planning approaches to solve electrical multiple-criteria based problems.

The first one is the 'Neoclassical' approach which tries to reduce all criteria to one expressed in monetary terms, by economic valuation of environmental or social criteria. Several methodologies have been developed for this purpose, among which we may cite the ExternE methodology as most wide spread and successful. However still few decision makers dare to rely on the values produced, because of the large uncertainties underlying the monetary valuation social and environmental impacts [Fang and Hill, 2003].

The second approach is based on the multiple criteria decision making (MCDM) methods, which attempt to aggregate the different criteria by means of the preferences towards them for all actors involved in the decision making process. Although this approach may be considered more subjective, it is greatly valued because it allows a greater participation of these actors, and also because it is more transparent and flexible than the monetary valuation approach [Linaires and Romero, 2002].

The MCDM framework creates an environment where alternatives or options are evaluated on an equal footing. However concerns about difficulties of using the more complex MAUT models in practice led to the development of the Simple Multiple Attribute Rating Technique (SMART) which is a multiple criteria decision making technique that utilizes a number of discrete evaluation criteria within a Multiple Criteria Decision Making (MCDM) environment to examine and assess the trade-offs between alternative solutions.

The technique has benefited from the long standing interests of psychologists, engineers, management scientists and mathematicians who have brought a continuing awareness of behavioral and social issues as well as underlying theory [Belton and Stewart, 2002].

The MCDM technique used for this research project is the Simple Multi-attribute Rating Technique (SMART). Where the total decision score for each solution is determined by calculating a score for each criterion and multiplying this by the weight value assigned to that attribute by the decision maker. The decision score for a solution obtained from each criterion is dependent on its performance relative to the other alternative solutions. With the SMART method in this research project context ,the most desirable solution rating-in each criterion-is given a decision score of 10,with the least desirable solution rating decision score of 1.The other solution ratings are given a decision score for that criterion based on how close they are to the most or least desirable ratings-using a linear scale. The total decision score for each alternative solution is then determined using a linear additive function to sum the individual score for each criterion.

2.6 Research Question Answered

This chapter has provided preliminary answers to the research questions posed in chapter one and are answered below as follows:

Which methods/approaches of electricity distribution system planning are currently being used in Kenya and how effective are they with regard to Kenya Vision 2030 objectives?

Following the outcome of the three assessment studies that have been analyzed in the sections of this review, it can be seen that in Kenya electricity distribution system is currently operated and maintained by the Kenya Power and Lighting Company (KPLC) and the Rural Electrification Authority (REA). The former is a profit driven government parastatal with the mandate to purchase bulk electricity supply, transmit, distribute and retail electricity to end use customer through out Kenya. In the course of carrying out its mandate the company ensures its expansion projects and programmes are reflective of infrastructural developments for the electricity sub-sector as envisaged in the Government economic policy and national development objectives. REA is a government agency with a specific mandate to speed up the implementation of rural electrification/distribution (Section 67 of the Energy Act of 2006).

Hence these two organizations have different goals when it comes to planning of the electrical distribution system .As a result different planning approaches/models have been used. Out of the three assessment studies "the Kenya Vision 2030 Electricity Distribution Expansion Plan" is the only one that vaguely addresses the Vision 2030 objectives with respect to electricity distribution. The LCPDP is focused on transmission and generation scale-up programmes while the Earth Institute study is concerned with the national electrification/distribution coverage but from the least-cost investment perspective. Hence no particular planning approach addresses electricity distribution panning holistically and especially with regard to "Kenya Vision 2030" objectives.

Which planning method or approach is compatible and viable to the electricity distribution system in Kenya? And how can it be modeled for applicability in achieving the "Kenya Vision 2030" objectives?

Electricity distribution system planning is a process that involves many stakeholders with diverse interests and multiple objectives (see appendix B).

Byrne and Mun [2003] suggest that in such a scenario, a 'policy commons' approach to planning should be emphasized, in which diverse elements of the society can participate in decision making on capital investment, price setting, and technology development, environmental and social goals relating to electricity provision. When participation of all the stakeholders, not only from the government and business sector but also from the civil society is institutionally encouraged and supported and diverse concerns of different stakeholders are discussed in an open and transparent manner. The aims and needs of the society regarding electricity service delivery can be better clarified, and the possibility of reaching a consensus can be advanced.

This research project proposes a planning methodology which is based on the Espie P et al 2003, Wang and McDonald 1994 planning model known as *Simple Multiple Attribute Rating Technique* (SMART).

This is a multiple criteria decision making technique that utilizes a number of discrete evaluation criteria within a multiple criteria environment to examine and assess the trade-offs between alternative solutions. By embedding this technique in a "bottom-up" planning process a model may be developed that is compatible with the traditional optimization planning approaches currently being used by the Kenyan power sector and also allows for a more likely possibility of achieving “Kenya Vision 2030”.

2.7 Onward

At the end of chapter one it appeared useful to review the outcome of three latest major assessment studies which were carried on the Kenyan power sector with relation to electricity distribution planning and “Kenya Vision 2030” objectives and also review the published literature especially on different models/approaches to electricity distribution system Planning.

It has emerged from this review that the three assessment studies mentioned above are more concerned with the solution of electricity load demand growth and accessibility problems. The way the problems are being mitigated is by increasing generation and transmission network capacity without seriously considering other pertinent issues e.g. environment, societal impact, system reliability, distributed generation, quality of supply etc which are an integral part of today’s dynamic nature of the electricity distribution planning industry.

Such solutions in the long run may render the plans to be cost effective.

In other words, network problems will be solved as they arise without insight to the future problems which in the long run will tend to be expensive and coupled with unplanned developments.

Previous work has shown that electricity distribution system planning can be formulated as a multiple criteria decision making problem. The technique provides solutions to the problems involving conflicting and multiple objectives.

With regard to this finding this research project intends to apply an MCDM technique embedded in a 'bottom-up' planning process to assess the implication of Vision 2030 (National policy) on electricity distribution system planning in Kenya. The technique is expected to come up with a flexible and robust plan which will make the Vision 2030 objectives more likely to achieve.

CHAPTER THREE: ELECTRICITY DISTRIBUTION PLANNING THEORY DEVELOPMENT

3.1 Introduction

Chapter two outlined the three recent major assessment studies carried out on the Kenyan power sector and also reviewed the published literature on electricity distribution system planning approaches/methods. Based on the findings of these assessments and the planning literature reviewed, this chapter intends to set up the framework by which electricity distribution system planning methodology for this research project is developed.

3.2 Proposed planning methodology

The proposed planning methodology begins with identifying the area of the distribution network under evaluation which in this case is the 33 kV electricity distribution network in the Coastal Region of Kenya. The 33 kV distribution network has been chosen because most of the data was readily available and accessible. It also acts as the backbone for distribution feeders of this region hence it supplies all the major District headquarters in the region.

This network is subjected to a planning period of 20 years i.e. (2010-2030) according to "Kenya Vision 2030" plan. All relevant problems relating to the distribution network within the planning period are identified. Owing to uncertainty of load growth three different scenarios are considered i.e. 2012, 2022 and 2030 as per the Kenya vision 2030. The three scenarios also consider the envisaged developments within the planning horizon year.

An evaluation criterion is selected and the number of possible options combinations for each identified problem(s) is established. Then data describing the impact of each solution with respect to the selected criteria is generated for final analysis.

Within the context of this research project 'problems' are assumed to represent specific network issues such as an overloaded or unreliable circuit. 'Options' are the measures available to the utility planner to address each problem and a 'solution' is composed of a group of options. Consideration is also given to problems or potential problems that might occur, even if the probability of this happening is very small.

The theory developed for this research project, as will be discussed in the progressing sections is based on the tasks within the proposed planning methodology illustrated in Figure 3.1.

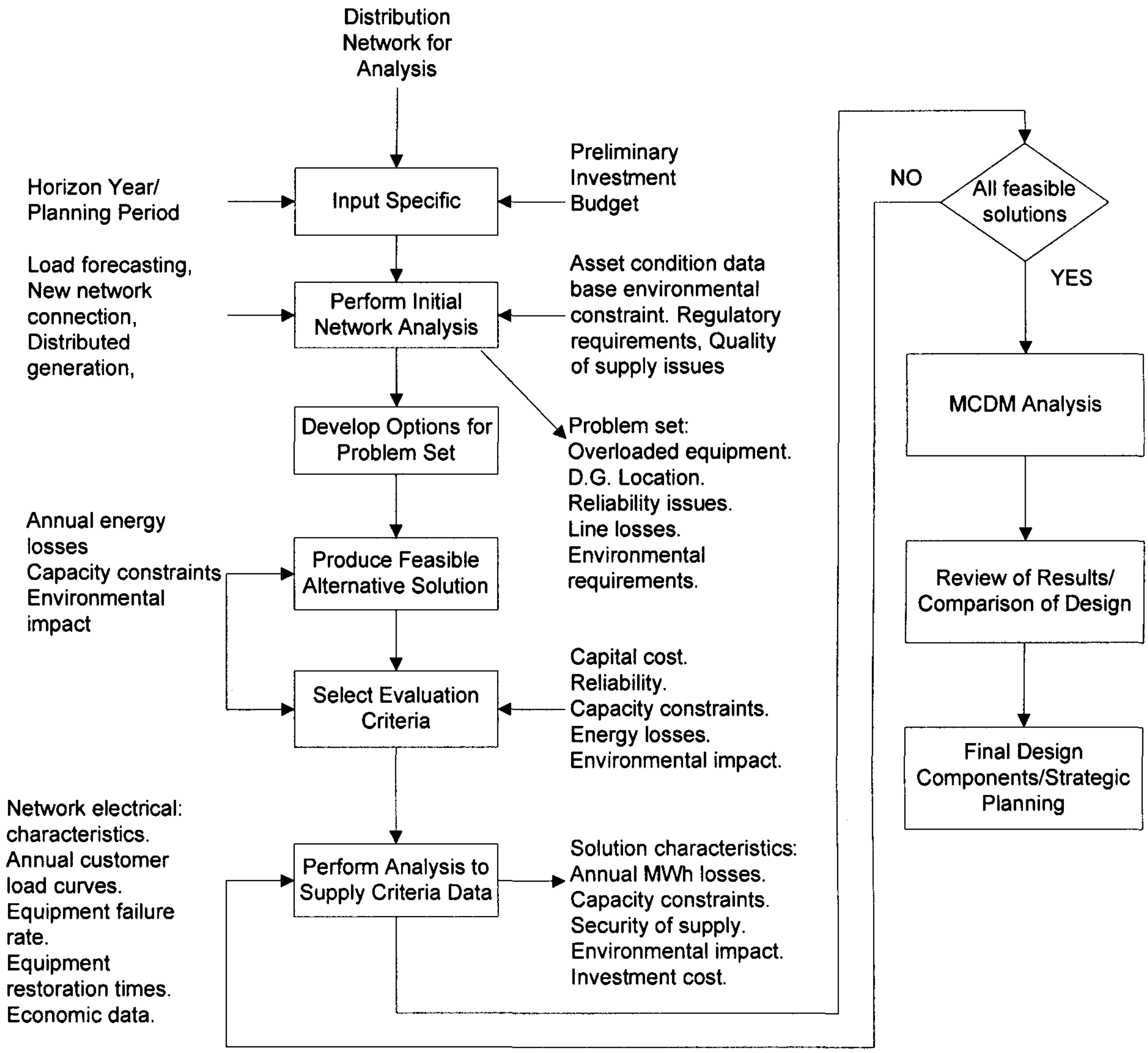

Figure 3.1 Flow Chart of Proposed Planning Methodology [Source: Espie et al, 2003].

3.3 Initial Network Analysis

The initial task is to choose a network for analysis (see fig 3.1).The input specifications are the planning period in this case 20 years according to the "Kenyan Vision 2030" plan, and a preliminary budget which is worked out based on the envisaged network development in the region (see distribution costing in chapter five).

Forecast load data for each load point up to 2030 are used to carry out load flow calculations/analysis in DigSilent software. To allow the impact of uncertainty to network load growth to be taken into account three load scenarios will be considered for a planning period of 20 years. The three load scenarios represent approximate annual load growth of 6% as per the LCPDP report [2009] and also consider the likely change in political regimes in the years 2012, 2022 and 2030. During the load flow analysis network problems are identified e.g. overloaded circuits (lines) or equipments (transformers), and load points experiencing reliability problems.

3.4 Develop Options for Problem Set

With the knowledge of the expected and potential problems, a set of options that address each problem is specified. For an overloaded circuit this may consist of a choice of circuit capacities and construction types as well as a choice of routing [Espie et al, 2003]. Consideration is also given to solutions options that address two or more problems simultaneously. Equipment selected must have the ability to serve consumers within statutory voltage limits and adhere to security standards. The equipment therefore requires screening through network analysis before consideration.

3.5 Produce Feasible Alternative Solution

Once all options have been specified for each existing and expected network problems, a solution can then be produced for evaluation. A solution as mentioned earlier is defined as a set of one or more options addressing all the problems identified. It is worth noting that each solution must incorporate at least one option from the set specified for every identified problem.

3.6 Selecting Evaluation Criteria

The selection of evaluation criteria depend largely on the preference model being used and the range of alternatives under consideration .The three assessment studies carried out on the Kenyan power sector revealed that all parts of the power system in Kenya i.e. generation, transmission and distribution require a scale up or expansion programme due to the high forecasted load demand growth. Keith et al [2008] writes that the major concerns of Electricity Distribution System Planning are;

- Financial considerations
- Service quality and reliability
- Environmental impact
- Public image.

These factors form the basis from which this research selects its planning evaluation criteria. It is worth noting that there are many criterions that may be considered but because of the objective of this research project two sets of criteria have been selected. The first set called "relative score", are embedded in the design process and represent accepted performance records and as such are considered objective.

These are capacity constraint, System security/Reliability and Annual energy losses. The second set, called "user preference weights," represent the users concerns and circumstances and are thus somewhat subjective and are assigned by the user. These are societal (electrification rate) and environmental impact [Atanackovic et al, 1997].

Notice the capital cost has not been considered as one of the criterion since it masks the technical benefit that each solution can provide. Never the less the capital cost of each solution is an extremely important attribute and will be considered during the planning process. The impact of different capital budgets can be easily assessed when the capital cost of implementation is de-coupled from the technical benefits that each solution can provide [Espie et al, 2003].

The next section contains the description of the selected criterion models and the algorithms for the selected attributes, the model reflects the basic technical and financial aspects of the network. In other words the focus is on a techno-economic optimization.

3.6.1 Capacity Constraints

According to Espie et al [2003] one way of dealing with the annual load growth uncertainties is to consider possible load scenarios and assess each planning solution to identify where the system capacity remains below the forecasted scenario load.

In the proposed methodology the consequences of adverse scenarios is determined by performing a load flow calculation for each feasible solution for all load scenarios. If a particular item of equipment is overloaded (in one scenario), then the nearest load is reduced until the overload is removed or the equipment is upgraded / replaced with an equipment of higher rating. If this calculation is performed for a number of loading intervals (representing the annual load curve) a figure for the annual curtailed demand can be obtained for each solution. The next section presents the basic algorithm for the AC load flow.

AC load Flow

Load flow calculations in network planning are needed for two purposes: to check whether the network meets operational constraints and to find power losses for the particular state of the network. The main feature of load flow calculation for the network planning tasks is that it should be done many times and therefore it must be very fast [Neiman, 2001].

In a general case the network can be described by its π equivalent. Then, omitting shunt capacitance of the distribution lines, the transmitted can be expressed as:

$$P_{ik=V_i}[V_{g_{ik}} - V_k(g_{ik}\mathrm{Cos}\delta_{ik} + b_{ik}\mathrm{Sin}\delta_{ik})] \tag{3.1}$$

$$Q_{ik=V_i}[V_{ik}(-b_{ik}) - V_k(g_{ik}\mathrm{Cos}\delta_{ik} - b_{ik}\mathrm{Sin}\delta_{ik})] \tag{3.2}$$

Where P_{ik} *and* Q_{ik} are respectively transmitted real and reactive power from node i to node k, V_i is the voltage at node i.

δ_{ik} is the angle between two voltage vectors i and k as shown in the expression below.

$\delta_{ik} = \delta_i - \delta_k$.

b_{ij} and g_{ij} are respectively the line susceptance and admittance.

The state of the system is defined if the voltages and angles at all the nodes are known. These can be obtained solving the following system of power balance equation:

$$P_i = \sum_{k=1}^{n} P_{ik} = V_i \sum_{k=1}^{n} V_k \left[G_{ik} \cos \delta_{ij} + B_{ik} \sin\delta_{ij}\right] \quad \textbf{(3.3)}$$

$$Q_i = \sum_{k=1}^{n} Q_{ik} = V_i \sum_{k=1}^{n} V_k \left[G_{ik} \cos \delta_{ij} + B_{ik} \sin\delta_{ij}\right] \quad \textbf{(3.4)}$$

Where n are number of buses, P_i and Q_i respectively real and reactive net power production at node i

B_{ik} and G_{ik} are the imaginary and real parts of the admittance matrix.

The classical approach applied to solve this system of equation is Newton Raphson method. However, the distribution networks have certain features in comparison with other power system objects. The main difference according to [Neiman, 2001] can be listed as:

- Radial or weakly meshed structure
- High R/X ratio
- Unbalanced loads
- Dispersed Generation.

Therefore, distribution networks fall into a category of ill-conditioned power systems for generic Newton-Raphson and fast decoupled load flow methods.

Single-phase Alternating Current (AC) representation is the most popular analysis method for distribution network. Numerous algorithms developed specially for calculation of AC load flow in the distribution networks are available [Srinivas, 2000], a computationally efficient solution scheme based on Newton-Raphson method is proposed by [Esposito and Ramos, 1999].

A large group of methods exploits the radial configurations of distribution network .These algorithms consist of two basic steps namely backward sweep and forward sweep.
The backward sweep is a current or power flow summation with possible voltages updates. The forward sweep is a voltage drop calculation with possible current or power flow updates [Neiman, 2001].

Chen and Chen [1991] presented the Z-bus method which is based upon the principle of superposition applied to system bus voltages. The voltage of each bus is considered to arise from two different contributions; the specified source voltage and equivalent current injection.

3.6.2 System Security/Reliability

A key criterion within any planning methodology is the impact of each solution on the distribution network reliability. Quantitative reliability estimation is being recognized as necessary and is becoming feasible in the planning of electricity distribution systems [Allan and Silva, 1995].
The improvement in the network reliability level,or the decrease in interruptions, cost, usually lead to an increase in investment cost. According to Neiman [2001] there are well developed methods for approximate reliability assessment for distribution network in

existence, which are suitable for planning purposes, since they allow for compelling reliability estimation for each state of the network. The next section gives a brief introduction to Reliability analysis with respect to distribution planning.

Basic Reliability Indices

Billiton [1995] notes that at distribution level, basic power supply reliability is defined by two sets of indices, namely, the load-point indices and the system performance indices. The primary reliability indices at a customer point are:

- Expected frequency of failure **λ;**
- The average duration of a failure ***r*;**
- The average annual outage time (Unavailability), ***U***.

These indices depend on many factors such as, reliability of individual items of equipment circuit length and loading, network configuration, load profile and availability transfer capacity.

In radial distribution systems the calculations of reliability indices involve a system consisting of series components from source to load. Supposing there are *n* components in series, the system failure rate λ_s will be:

$$\lambda_s = \lambda_1 + \lambda_2 + \cdots \lambda_n \qquad \textbf{(3.5)}$$

And the system failure durations r_s will be:

$$\mathbf{r}_s = \frac{\lambda_1 r_1 - \lambda_2 r_2 + \cdots \lambda_n r_n}{\lambda_1 + \lambda_2 + \cdots \lambda_n} \qquad \textbf{(3.6)}$$

The system interruption time U_S,will be:

$$U_S = \lambda_{s.}r_s = \lambda_{1.}r_1 + \lambda_2.r_2 + \cdots \lambda_{n.}r_n \quad (3.7)$$

Equipment failure rates and failure durations are the data obtained from statistics and their values vary in certain ranges. Even for the same equipment there are many types and sizes. These values depend also on the age of the particular piece of equipment.

Customer Interruption Cost

Reliability has been recognized as an important part of the system planning task. But it is also important to take into account the market value of a particular customer [Allan and Silva, Chen et al 1995, and Neiman 2001].

This could be done through a Customer Interruption Cost (CIC) evaluation, which is defined as a measure of the monetary losses for customers due to an interruption of electric service Customer Interruption Cost reflect the service value provided by a utility to the customer and the inconvenience or damage experienced by it's customers if a power failure occurs.

For many types of customers the issue of service reliability is simply a question of whether the supply is available or not .Other customers have more stringent quality requirements Therefore, in the nearest future, the utilities will face the problem of providing differentiated levels of reliability for different customers [Neiman, 2001].

Reliability as Planning Attribute

Thus, the value which combines network utility unavailability data with customers view on availability of supply can be used as reliability criterion in planning tasks [Chen et al, 1995]. The corresponding attribute is calculated according to the following equations:

$$C_{Reliab} = \sum_{i=1}^{m} I\,C_i = \sum_{i=1}^{m} = \left(\sum_{i=1}^{m}(\lambda_j r_j P_i CIC_i(r_1)\right) \quad \textbf{(3.8)}$$

Where the reliability criterion C_{Reliab} is calculated as a sum of load node interruption costs IC_i.

The interruption cost is calculated for each node in the network as a sum of interruption cost due to possible failure of each upstream element, m(j), from the node to the feeding point. Finally, λ_{j}, is a failure rate of the element j, r_j is its average outage time, P_i is average load point and $CIC_i\ (r_1)$ is customer interruption cost due to failure of duration r_i,

The energy not supplied is given as ;

ENS = total energy not supplied by the system = $\sum P_i\ U_i$ becomes **(3.9)**

$$\text{ENS} = \sum_{i=1}^{m} = \left(\sum_{i=1}^{m}(\lambda_j r_j P_i\right) \quad \textbf{(3.10)}$$

Unavailability is calculated for each node in the network as a sum of interruption cost due to possible failure of each upstream element, m(j), from the node to the feeding point, λ_j is failure rate of element ***j***, r_j is its average outage time P_i is the load at point i.

The reliability attributes must be calculated for each load model. Moreover, the economic principle must be taken into the consideration even in case of equation (3.10), despite the fact that the ENS is an energy value .Thus the annual value of ENS must be multiplied by

$$K=(1+i)^{-t}$$

Where K is the value of future amount in the year ***t*** and ***i*** is the interest rate.

For this research project ,since the information about the customer interruptions costs is not available, individual load point indices for each load point are used to compute the percentage outage per year of each load point and compare it with the Loss of Load Expectation (LOLE) specified in the LCPDP report [2009] which is 4 days/year.

3.6.3 Annual Energy Losses

The aim of the annual loss criterion is to provide an accurate assessment of the power losses associated with each planning solution. In this research project only the real power losses associated with each solution will be considered. This is because real power gives a reflection of the technical quality of the network. However, because the MCDM allows the use of all criteria with significantly different units of measurements, reactive power losses could also be assessed if required.

3.6.4 Environmental Impact

Environmental concern in cable distribution networks is caused mainly by oil leakages from pressurized oil filled insulated cables. However; cables of this type are being replaced by XPLE insulated cables. On the other hand, the visual impact and the land usage may become the major factors in planning of the overhead lines, since most of the 33 kV lines in Kenya are overhead lines. Leakage of oil from substations and distribution generators may also be considered when evaluating environmental impact if explicit data on them is made available, although for this research project only weighted line length data was available.

Therefore, the methodology adopted for this criterion is to consider the total circuit length of new or modified network circuits. For each new or modified circuit, the length is weighted to represent the likely environmental impact associated with the visual obstruction and implementation of each circuit type and route. This weighted length is then summed over all new or modified circuits to determine a weighted value for each planning solution [Atanackovic et al, 1997 and Espie, 2003].

3.6.5 Capital Cost

Capital cost is an important factor when assessing alternative planning solutions. With the proposed methodology this is a summation of the costs involved in implementing each of the options selected for each identified problem plus any ongoing costs related to implementation or the other operational aspects associated with the distribution network [Khatib, 1996 and Espie et al, 2003].

The cost of each option (and solution) should be expressed either as the current cost of implementation or as the future–worth equivalent at the end of the planning period (horizon year), converted using present–worth calculations.

According to Neimane [2001] Present value (PV or worth) analysis is a method of measuring and comparing costs and savings that occur at different times on a consistent and equitable basis for decisions making.

To convert the single payments at some year *t* in the future into equivalent amount at present and vice versa the Present Value method can be described as:

$$PV = \frac{1}{(1+i)^t} FV \tag{3.11}$$

$$\mathrm{FV}=(1+i)^t \mathrm{PV} \tag{3.12}$$

Where FV is a value of future amount in the year *t*, *PV* is the value of the same amount at time zero and *i* is the interest rate.

If there are uniform series of the annual payments from today through *T* years the present worth of these payments can be found by using the Annuity methods:

$$\mathrm{PV} = \left[\frac{(1+i)^T - 1}{i(1+i)^T} \right] . \mathrm{A}, \tag{3.13}$$

Where A stands for value of annual payments, which is considered constant and T corresponds to the planning period.

In network planning tasks, different alternatives are usually analyzed over a longer period of time corresponding to the life time of the equipment. However, the life time of different units of the equipment may differ considerably. One solution to the problem of the dynamic allocation of assets is to use one of the accounting depreciation methods. Depreciation may be defined as lessening in value of a physical asset with the passage of time.

Thus, the alternative investments, which do not coincide in time, can be compared based on the Present Value (PV) of the investments and the salvage value. Another, conceivable and more generalized approach is to reduce a single investment to a series of annualized costs [Neiman, 2001 and Khatib, 1996] as shown in eqn 3.14

$$A = \left[\frac{i(1+i)^T}{i(1+i)^T - 1} \right] PV. \qquad \textbf{(3.14)}$$

If one defines the lifetime of the particular unit of the equipment as depreciation time and assigns the planning period, the following cases may need to be compared with each other.

Case 1: Planning period is shorter than the unit depreciation time and the investment is made at present time. The planner is only interested in payments to be made during the planning period. A series of annualized costs can be found from the following equation:

$$A_{Depr} = \left[\frac{i(1+i)^{T_{Depr}}}{i(1+i)^{T_{Depr}} - 1} \right] PV \qquad \textbf{(3.15)}$$

The present value of the investment during the planning period may be found applying the equation (3.13).

Case 2: Planning period may be shorter than or equal to the unit depreciation time, but the investment is postponed by a number of years more than $T_{Depr} - T_{Pt}$.

In this case a series of annualized costs to be found from equation (3.15), and used to find the future investment value as follows:

$$FV_{pt} = \left[\frac{(1+i)^{T_{Pt}-T_0}}{i(1+i)^{T_{Pt}-T_0}}\right] . A_{Depr} \qquad \textbf{(3.16)}$$

Where T_0 is the time of delay of the investment in comparison to the present time. The present value of the investment can be obtained either from equation (3.16) by applying eqn (3.11) or directly from the physical value of investment according to eqn 3.17 below

$$PV = (1+i)^{-T_0}\left[\frac{1-(1+i)^{T_{Pt}-T_0}}{1-(1+i)^{-T_{Depr}}}\right] . PV \qquad \textbf{(3.17)}$$

Equation (3.17) was obtained from equations (3.11), (3.15) and (3.16),

Case 3: Unit depreciation time is shorter than (or equal to) planning period. In this case the present value of the investment is equal to its physical value, but annuity can be calculated using equation (3.15).

For the purpose of this research project the capital cost will be calculated separately for each alternative solution but is not included as one of the criteria. The calculated capital cost of each alternative solution will be compared to the capital investment budget envisaged in the Vision 2030 power development plan for the test region only after all the technical benefits have been evaluated to determine the most techno-economic solution.

3.7 MCDM Analysis

It should be noted that the MCDA or MCDM models are meant to unfold decisions through a process of learning, understanding, information processing, and defining the problem and its circumstances. The emphasis must not be on the process, nor the act or the outcome of making a decision .In other words the focus of the models is on supporting or aiding decision making, it is not on prescribing how decisions "should" be made, nor is it about describing how decisions are made in the absence of formal support. The analysis helps to structure the problem, hence serves to complement and to challenge intuition, it acts as a sounding –board against which ideas can be tested. It does not seek to replace intuitive judgment or experience. The process leads to better considered, justifiable and explainable decisions i.e. the analysis provides an audit trail for a decision [Belton and Stewart, 2002].

Choosing among all the MCDA methods that exist can be a multi-criteria problem in itself. Each of the methods has its own advantage and drawbacks, and it is not possible to claim that any of the methods is generally more suitable than the others are. Different Decision Makers will always disagree about which methods are most appropriate and valid. The choice of the method mostly depends on the preferences of the Decision Makers and the analyst. It is important to consider the suitability, validity and user-friendliness of the methods. It is also important to realize that use of different methods will most probably give different recommendations. This should not lead to the conclusion that there is anything wrong with any of the methods, it just means that the different methods work in different ways and are also used to solve different types of problems [Loken, 2005].

There is no doubt that if properly applied MCDA can be a very useful tool for planning electricity distribution systems, which is known to be complex in nature. For this research project the MCDM chosen is the Simple Multi Attribute Rating Technique (SMART), which has mostly been applied in Electricity Distribution System Planning [Wang and McDonald 1994, Linaires, 2002 and Espie, 2003].

3.8 Onward

Modeling is an approximate reflection of the reality. The good model must essentially consider the most important features of the real system and neglect unnecessary excessive details. The mission of the model is to gather numerous data about the problem under a single framework, and to process this data in such a way that the planning objectives can be expressed numerically in terms of attributes.

The model proposed in this chapter is dynamic and multiple-criteria i.e. the identified optimization objectives are treated separately. The corresponding attributes are calculated for the planning period as a sum of the annual and discounted terms.

Annual losses are obtained from the load flow calculations while the reliability criterion is evaluated using the load point indices, since the interruption costs are not available.

Total length of new or modified circuit is weighted to represent the likely environmental impact associated with the visual obstruction and implementation of each circuit and route. Investments for the particular state of the network are calculated as a sum of annuities of each investment in reinforcement action realized during the planning period.

The proposed planning model is tested on an existing 33 kV electricity distribution network located at the coastal region of Kenya.

A key benefit of this approach is the ability to make strategic planning decisions relating to the system and particular planning problems simultaneously. For example, analysis may identify several planning options that can be implemented for a particular planning issue depending on the scenario or future that occurs. The proposed planning methodology provides the utility with a microscopic overview of the entire network including the envisaged developments within the horizon planning period. This enables the utility decision maker to defer some of the planned network developments until the appropriate time.

In other words it makes prioritization of project easier ensuring techno-economic optimization.

The next chapter is a case study demonstrating the application of the proposed methodology on a 33 kV distribution network in the coastal region of Kenya.

CHAPTER FOUR: DISTRIBUTION SYSTEM PLANNING CASE STUDY

4.1 Introduction

This chapter is a case study of the electricity distribution network in the coastal region of Kenya comprising of thirteen load centers, representing the accumulated load of the 33 kV distribution network at each connection point, as well as 18 existing and potential transformers, overhead lines and local generators. To allow the impact of uncertainty owing to network load growth to be taken into account three load scenarios have been considered for the planning period, which is assumed to be 20 years (2010-2030) as per the "Kenya Vision 2030" Plan. Each of the three load scenario considers the envisaged developments, network problems and alternative options/solution to solve the problem. The network has been analyzed in three phases or scenarios i.e. 2012, 2022 and 2030.These scenarios are based on a 6% average annual load growth rate forecasted in the [LCPDP 2009] report (See Appendix A). The objective of the case study is to demonstrate the applicability and sensitivity of the multiple criteria decision making technique to the electricity distribution system planning problems. Secondly is to show the ability of the chosen planning approach to make strategic decisions relating to the whole network and also particular planning problems simultaneously within the planning horizon period.

4.2 Fundamental Information on the Existing Network.

The proposed planning project deals with a long term planning of the 33kv distribution network in the Coastal region of Kenya.

Figure 4.1 (DigSilent software drawing) shows the existing network with the current 12 substations/load points with a total approximate peak load of 230MW and two local thermal Generators producing a total of 90 MW. The 33 kV network covers a distance of approximately 174km within the region. The 132 kV grid connects four primary 132 kV/ 33 kV substations at Voi, Rabai, Kilifi and Kipevu.

The forecasted equivalent load at each 33 k V connections point and simulated percentage loadings for the three load scenarios are shown in Tables 4.1, 4.2 and 4.3 (See Appendix C) The 33 kV distribution network has been chosen because most of it's data was found to be readily available and also acts as the backbone of distribution feeders for this region hence it supplies all the major District headquarters in the region. The relevant problems relating to the distribution network within the planning period are identified (assumptions are made where necessary) and alternative options/solutions are also identified by performing a power flow analysis /calculation using Dig Silent version 14 software.

Within the context of this research project 'problems' are assumed to represent specific network issues such as an overloaded or unreliable circuit. 'Options' are the measures available to the utility planner to address each problem and a 'solution' is composed of a group of 'options'.

The equivalent percentage score of each alternative solution is computed with respect to the four basic criteria adopted for this project i.e. Capacity constraint, Reliability, Annual energy losses and Environmental impact. Note that a separate capital cost for each alternative solution will be calculated in the next chapter, but it's not included as one of the criterion. This is to ensure that the technical benefits of each solution are not obscured by the associated solution capital cost. The capital cost is later used to compare each solution with the capital investment budget to determine the most desirable solution and aid in the decision making process.

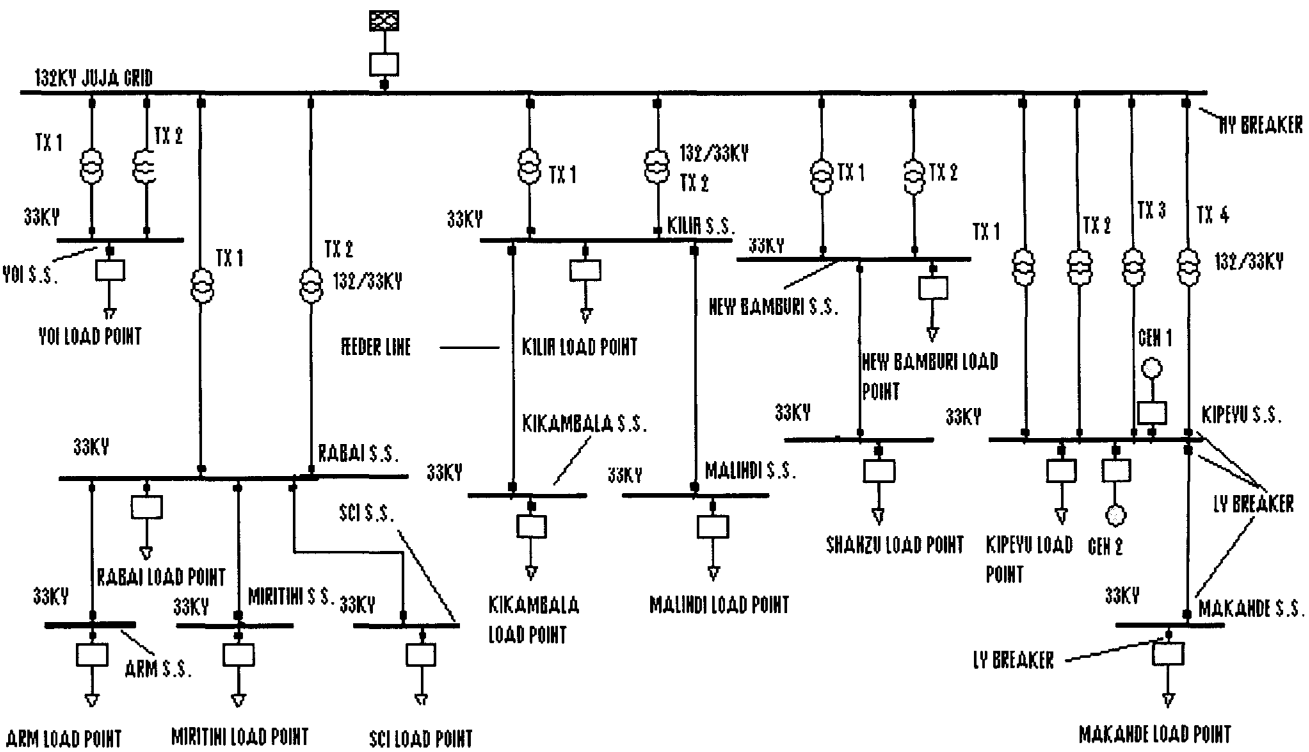

Figure 4.1 Existing Test Distribution Network [Source: KPLC, 2009}.

Table 4.1 shows the simulated load flow calculations and percentage loading of transformers and lines on the existing distribution network. From the load flow analysis results, evaluation of capacity constraints, reliability of the load points, annual energy losses, and environmental impact data are carried out as will be shown in the foregoing sections.

Table 4.1 Percentage Loading on the Existing Network

Substation Tx	MW	MVAr	% Loading	LINES/Tx	MW	MVAr	% Loading
Voi Tx 1	2.19	1.02	48.22	Rabai-ARM	6.17	3.7	93.75
Voi Tx 2	2.19	1.02	48.22	Rabai-Miritini	11.17	5.88	96.55
Rabai Tx1	35.03	16.78	43.16	Rabai-SCI	19.55	8.52	98.73
Rabai Tx 1	35.03	16.78	43.16	Kilifi-Kikambala	2.31	1.01	99.41
Kilifi Tx 1	15.33	7.25	113.31	Kilifi-Malindi	18.00	7.84	99.54
Kilifi Tx 2	23.50	11.12	113.31	NewBamburi-Shanzu	8.23	3.59	98.63
New Bamburi Tx 1	7.83	3.41	37.31	Kipevu Tx2	9.50	15.15	29.8
New Bamburi Tx 2	15.32	6.87	37.31	Kipevu Tx3	4.75	7.85	29.8
Kipevu Tx1	9.50	15.15	29.8	Kipevu Tx4	4.75	7.85	29.8

The following problems were identified from the simulation results on the existing network;

- Kilifi substation transformers 1 and 2 are overloaded at peak demand by about 13.31%.
- Kilifi-Malindi and Kilifi-Kikambala lines are heavily loaded at peak demand by 99.54% and 99.41% respectively.

The identified simulated options that may address these problems are arranged in option sets as follows;

- A_1- upgrading Kilifi TX 1 from 15MVA to 23MVA and Tx 2 from 23MVA to 30MVA results to 95.15% and 95.24% peak loading respectively.
- A_2 - Or reduce the load at Kilifi substation by upgrading the Malindi Substation from a 33/11kv, 7.5MVA to a 132/33kv, 23MVA Substation results to 58.74% loading at Kilifi substation.

It is important to note that the distribution transformers used in the case study are in the capacity range of 7.5,15,23 and 30MVA.

These could be attributed to the fact that the substations being considered in the case study are in the rural, semi-urban and urban areas hence the varied ratings. Though the desirable range from a planning perspective which makes the substations upgrading flexible are 7.5,15,30 and 60MVA etc.

4.3 Scenario Analysis

In order to assess flexible options and optimize on multiple criteria a modeling framework can be built around some planning package, which is used as a simulator to evaluate the plans generated externally. The framework generates many scenarios, the simulator evaluates them and either decision analysis or trade-off analysis techniques identify a preferred plan [Crousillat 1993]

To allow the impact of uncertainty owing to the network load growth to be taken into account three load scenarios are considered for the planning period, which is assumed to be 20 years (2010-2030) with respect to the "Kenya Vision 2030" Plan i.e. 2012, 2022 and 2030.Note that this scenarios have been chosen considering possible change of political regimes in each scenario. The scenario technique is presently the most widely used method for representing uncertainties in the planning task [Neiman, 2001].

According to Willis [1997] multiple scenarios is appointed as "the only completely valid way to handle uncertainty in transmission and distribution forecasting and reinforcement planning". The planner faces a difficult task of identifying uncertainties that could be of importance and may seriously influence the final solution, and those, which do not. The most useful and easiest approach is one that is termed "thematic"

This approach starts with themes (such as load growth" or "low load growth"); important variables are then identified and values for the variables are chosen that would corresponds to each of these different themes.

Neiman [2001] says that the scenarios should challenge assumptions, discount extrapolations and question historical trends and eventually take into account technological advancements.

He advises not to assign probabilities to events or trends, since this task is very difficult and there is no real benefit. Some of these general recommendations may be adapted to network planning while some may be argued.

The scenario technique according to Willis [1997] can be described by the following four steps:

Stage 1 Selection of alternatives to be examined.

Stage 2 Construction of scenarios by assigning plausible values to uncertain Parameters

Stage 3 Calculation of attributes for every scenario combining each future with each alternative plan.

Stage 4 Selection of a strategy according to a given decision criterion.

The next section evaluates the three scenarios that are being considered in this research project, taking into consideration the envisaged developments on the network, identified network problems and alternative options of solving the problems.

4.3.1 Scenario One 2012

Scenario 1 is the situation of the network at 2012.The envisaged development plans according to the LCPDP [2009] and Vision 2030 Secretariat [2008] reports are as follows;

- Construction of Rabai-Diani (SCI) 50Km of single circuit 132kv transmission line and a 132/33kv, 23MVA Sub-stations at Diani (Galu).
- Commissioning of the 90MW diesel plant in Rabai at the coast by2010.

Figure 4.2 shows the foreseen condition of the network by 2012 and Table 4.2 shows the simulated percentage loading of the transformers and line under scenario 1 with all the planned load growth developments included.

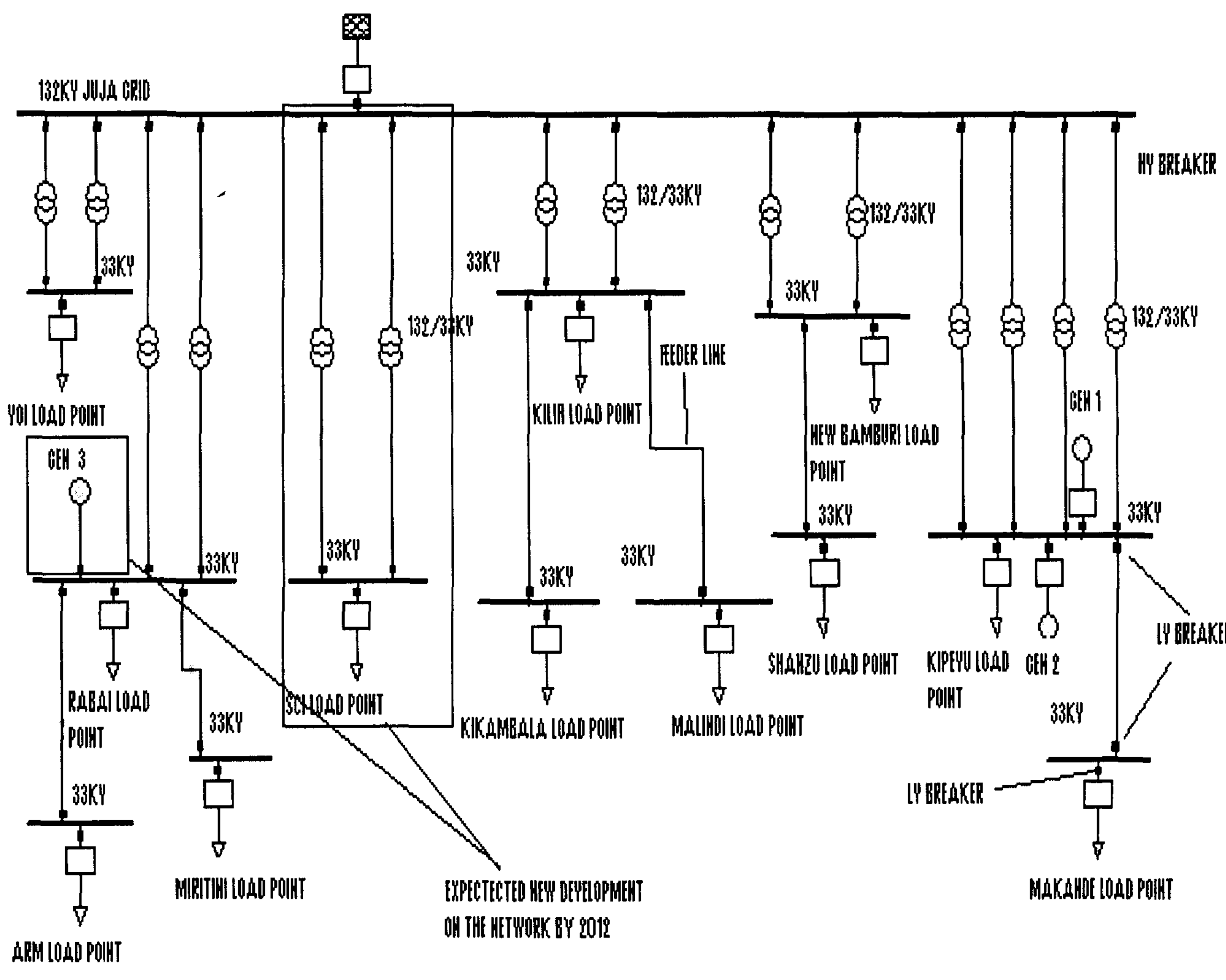

Figure 4.2 Distribution Test Network at 2012

Table 4.2 Percentage Loading of Scenario 1 (2012)

Substation Tx	**MW**	**MVAr**	**% Loading**	**LINES/Tx**	**MW**	**MVAr**	**% loading**
Voi Tx 1	4.01	2.54	94.94	Rabai-ARM	8.02	4.81	71.08
Voi Tx 2	4.01	2.54	94.94	Rabai-Miritini	14.52	7.64	95.10
Rabai Tx1	13.09	18.68	25.19	Kilifi-Kikambala	3.00	1.31	129.67
Rabai Tx 1	13.09	18.68	25.19	Kilifi-Malindi	23.40	10.19	99.99
Kilifi Tx 1	19.93	9.66	147.63	NewBamburi - Shanzu	10.70	4.67	128.42
Kilifi Tx 2	30.55	14.51	147.63	Kipevu-Makande	16.72	7.28	97.03
New Bamburi Tx 1	10.18	4.60	48.57	Kipevu Tx3	11.49	11.70	54.67
New Bamburi Tx 2	19.92	9.00	48.57	Kipevu Tx4	11.49	11.70	54.67
Kipevu Tx1	22.98	23.41	54.67	Diani (SCI) Tx 1	12.71	5.54	60.73
Kipevu Tx2	22.98	23.41	54.67	Diani (SCI) Tx 2	12.71	5.54	60.73

The problems identified from the simulation results on the network at Scenario 1 (2012) were as follows;

- Kilifi substation transformers 1 and 2 are overloaded at peak demand by about 47.63%.
- Kilifi-Malindi lines are heavily loaded at peak demand by 99.99%, while Kilifi-Kikambala line is overloaded by about 29.67%.
- New Bamburi-Shanzu line is overloaded by about 28.42%

The simulated options/solution identified that may address these problems are as follows;

- B_1 - Upgrading Kilifi Tx 1 from 15MVA to 23MVA and Tx 2 from 23MVA to 30MVA results to 95.15% and 95.24% loading respectively.
- B_2 - Or reduce the load at Kilifi substation by upgrading the Malindi Substation from a 33kV/11kv, 7.5MVA to 132/33kV, 23MVA Substation.
- B_3 - Upgrade the capacity of New-Bamburi-Shanzu, 5.7Km line conductor from Mulberry 150.9mm^2 with a resistance of 0.2648 Ω/Km to wolf 156.06mm^2 with a resistance of 0.2233 Ω/Km (see appendix D) to give 94.21% loading.

It is worth Noting that in option B_3 the upgrading of the line conductor results to less power losses due to I^2R hence reducing the load on the conductor. This is because increasing the cross sectional area of the conductor from 150.9mm2 to 156.09mm2 decreases the resistance from 0.2648 ohms /Km to 0.2233 ohms/Km since resistance is inversely proportional to the cross sectional area of the conductor. The bigger the cross sectional area of the conductor the less the power losses and the more power carrying capacity. On the other hand the higher the conductor cost in terms of material and installation cost.

4.3.2 Scenario Two 2022

Scenario 2 is the situation of the network at 2022. The strategic development plan is as follows;

- Reconstruction of the existing 60 km Rabai -Bamburi-Kilifi of 132 k V single circuit transmission line between Rabai and Kilifi on self –supporting steel lattice towers, instead of the existing wooden poles.
- Upgrading of Malindi substations to a 132/33k V, 23MVA Substations.

Figure 4.3 and table 4.3 shows the foreseen conditions of the network at 2022 and the simulated percentage loading of the transformers and line respectively with all the planned developments in place.

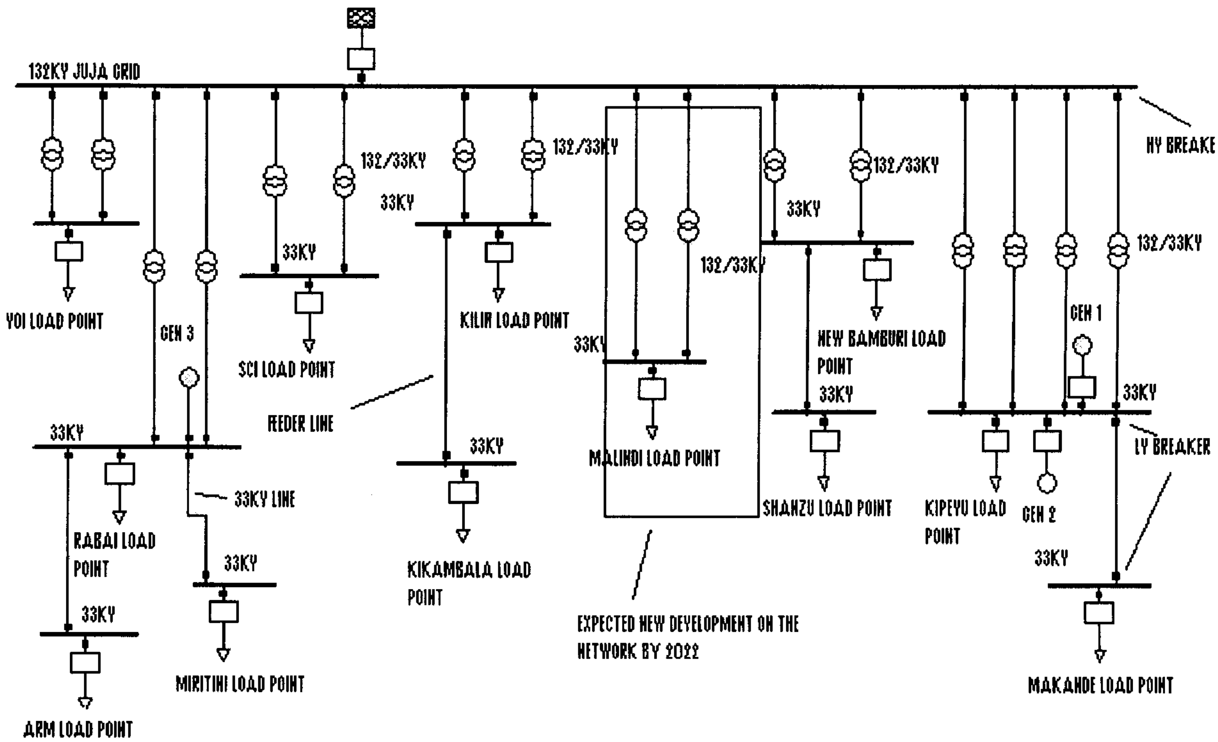

Figure 4.3 ***Distribution Test Network at 2022***

Table 4.3 Percentage Loading of Scenario 2 (2022)

Substation Tx	MW	MVAr	% Loading	LINES/Tx	MW	MVAr	% loading
Voi Tx 1	5.24	3.38	124.78	Rabai-ARM	10.49	6.29	93.04
Voi Tx 2	5.24	3.38	124.78	Rabai-Miritini	18.99	10.00	95.86
Rabai Tx1	2.06	13.32	14.90	Kilifi-Kikambala	3.93	1.72	98.73
Rabai Tx 1	2.06	13.32	14.90	NewBamburi-Shanzu	13.19	6.10	94.21
Kilifi Tx 1	13.98	6.67	102.97	Kipevu-Makande	21.86	9.52	97.26
Kilifi Tx 2	21.43	10.02	102.97	Kipevu Tx4	5.29	9.14	35.21
New Bamburi Tx 1	13.04	6.07	62.53	Diani (SCI) Tx 1	16.62	7.24	79.60
New Bamburi Tx 2	25.51	11.35	62.53	Diani (SCI) Tx 2	16.62	7.24	79.60
Kipevu Tx1	10.58	18.29	35.21	Malindi Tx 1	15.30	6.66	73.22
Kipevu Tx2	10.58	18.29	35.21	Malindi Tx 2	15.30	6.66	73.22
Kipevu Tx3	5.29	9.14	35.21				

The following problems were identified from the simulation results on the network at Scenario 2 (2022);

- Kilifi substation transformers 1 and 2 are overloaded at peak demand by about 2.97%.
- Voi Substation transformers 1 and 2 are overloaded at peak demand by about 24.78%

The simulated options that may address these problems are as follows;

- C_1 - Upgrade Kilifi Substation Tx 1 from 23MVA to 30MVA and Tx 2 maintained at 30MVA results to 98.25% and 98.78% loading.
- C_2 - Reduce the load at Voi substation by upgrading the Taveta Substation from 33/11k V, 2.5MVA to 132/33k V, 23MVA Substation

4.3.3 Scenario Three 2030

Scenario 3 is the foreseen situation of the network at 2030.The planned development is as follows;

- Commissioning of the 70MW Gas turbine plant in Kipevu at the coast.
- Upgrading the Taveta Substation to 132/33k V, 23MVA Substation.

Figure 4.4 and Table 4.4 shows the conditions of the network at 2030 and the simulated percentage loading of the transformers and line respectively with all the planned developments included.

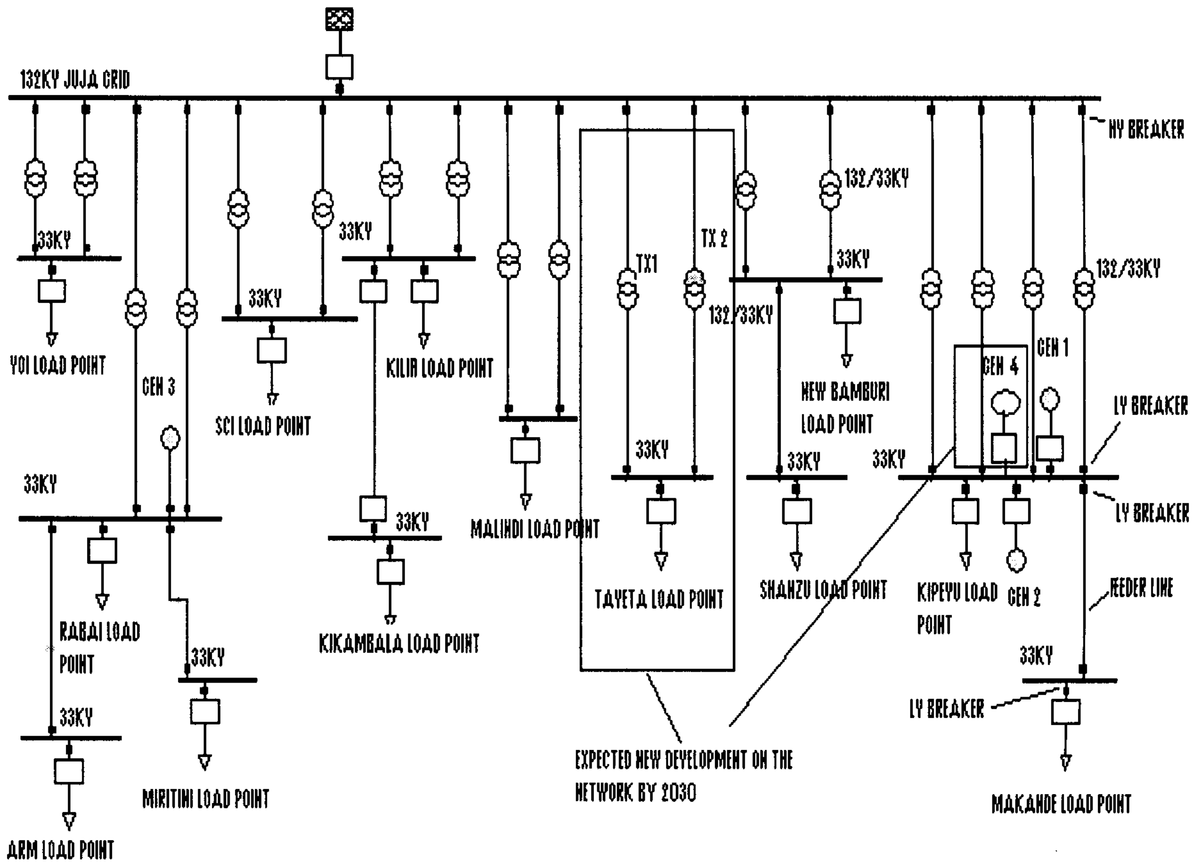

Figure 4.4 Distribution Test Network at 2030

Table 4.4 Percentage Loading of Scenario 3 (2030)

Substation Tx	**MW**	**MVAr**	**% Loading**	**LINES/Tx**	**MW**	**MVAr**	**% loading**
Voi Tx 1	2.18	0.98	47.93	Rabai-ARM	12.34	7.40	54.79
Voi Tx 2	2.18	0.98	47.93	Rabai-Miritini	22.34	11.76	56.45
Rabai Tx1	5.52	9.71	12.37	Kilifi-Kikambala	4.62	2.02	58.16
Rabai Tx 1	5.52	9.71	12.37	New-Bamburi-Shanzu	16.46	7.18	58.29
Kilifi Tx 1	16.44	7.83	121.43	Kipevu-Makande	25.72	11.20	57.33
Kilifi Tx 2	25.22	12.01	121.43	Taveta Tx 1	2.18	0.96	10.37
New Bamburi Tx 1	15.66	7.21	74.96	Taveta Tx 2	2.18	0.96	10.37
New Bamburi Tx 2	30.64	14.11	74.96	Kipevu Tx3	0.63	7.25	24.08
Kipevu Tx1	1.26	14.40	24.08	Kipevu Tx4	0.63	7.25	24.08
Kipevu Tx2	1.26	14.40	24.08	Diani (SCI) Tx 1	19.55	8.52	93.81
Malindi Tx 1	18.00	7.84	86.28	Diani (SCI) Tx 2	19.55	8.52	93.81
Malindi Tx 2	18.00	7.84	86.28				

The following problems were identified from the simulation results on the network at Scenario 3 (2030);

- Kilifi substation transformers 1 and 2 are overloaded at peak demand by about 21.43%.

The simulated options that may address these problems are as follows;

- D_1 - Upgrade Kilifi Substation Tx 1 from 30MVA to 60MVA and Tx 2 from 30MVA to 60MVA results to 94.17% and 93.34% loading respectively.
- D_2 - Or upgrade Kikambala substation from 33/11kv, 2.5MVA to 132/33k V, 23MVA Substation.

4.4 Identified Planning Issues for the Distribution Network

All the identified problems and number of options combinations are shown in table 4.5.It also highlights the number of possible options combinations for each identified planning problem which yields 72 alternative solution configurations for the distribution network.

Table 4.5 Identified Planning Issues for Coast Region Distribution Network

Problems	**Options Sets**	**Number of options combinations**
2 transformers are overloaded at peak demand of the existing load (2009)	A_1,A_2	2
2 transformers and 2 lines are overloaded at peak demand of scenario 1 (2012)	B_1, B_2, B_3.	3
4 transformers overloaded at peak demand of scenario (2022)	C_1, C_2.	2
2 transformers are overloaded at peak demand of scenario3 (2030)	D_1, D_2.	2
5 -33Kv loads experiencing reliability problems in some scenarios	E_1, E_2, E_3.	3
Total number of possible solutions		**72**

The next section briefly describes the evaluation of the equivalent percentage scores of each alternative option with respect to the four basic criteria. Two kinds of activities are performed, first is the conversion of the reliability load point indices to an equivalent percentage score.

Secondly the calculation of percentage scores with respect to the annual energy losses and the impact on the environment.

4.4.1 Load Point Indices Evaluation

Studies were performed on the Reliability Test System for educational purposes (RBTS) which provides data on two different distribution networks. The studies considered the base case which includes lines with disconnects fuses, alternative supply, and repair of transformers. To simplify, only the down times of the lines (originally 5hrs) were assumed to be log –normally distributed while failure rates of all components (0.015f/yr for transformers and 0.05f/y//Km for lines) and down times of transformers 200hrs are assumed to be exponentially distributed. The failure rate for lv, hv circuit breaker and 33 k V bus bar were given as 0.005f/y with 20hrs, 50hrs and 5hrs respectively. While the 132k V bus bar was given a failure rate of 0.002 with a repair time of 50 hrs [Billinton R et al, 2004].

Following the above study assumption the calculation for typical load point indices are done. Table 4.6(a) shows the reliability indices for Voi load point (see figure 4.1).The equipment that forms that load point are two transformers, two bus bars, three lv circuit breakers, and two hv circuit breakers, similarly the ARM load point equipments is a combination of the Voi load point equipment plus three lv feeder breakers, the 33kv feeder line and the 33kv bus bar 2 as shown in table 4.6 (b).

Table 4.6(a) Reliability Indices for Voi Load Point

Failed Components	λ (f/yr)	r (hours)	U (hours/yr)
132kv bus	0.002	50	0.01
Breaker 1	0.005	50	0.25
Transformer 1	0.01	200	2.0
Breaker 2	0.005	20	0.1
Breaker 3	0.005	50	0.25
Transformer 2	0.01	200	2.0
Breaker 4	0.005	20	0.1
Breaker 5	0.005	20	0.1
33 kv bus2	0.005	20	0.025
Total	**0.052**	**92.98hrs**	**4.835**

The calculations are carried as follows;

The outage time r_k for Voi load point = $\frac{U}{\lambda} = \frac{4.835}{0.052} = 92.98$ hrs

Percentage outage time /year = $\frac{92.98}{8760} * 100 = 1.06$ %

Following the same procedure in the Voi load point example, the calculated outage time for the ARM load point is calculated as 51.15 hrs and the percentage outage time per year is 0.49%.

Table 4.6 (d) shows the calculated annual percentage outage time of all the 13 load points in the network for all the three scenarios which represents the entire planning period i.e. from 2010-2030.

For load points like Rabai and Kipevu where Generators are connected additional indices derived from table 4.6(c) have been used for computation.

Table 4.6(b) Reliability Indices for ARM Load Point.

Failed Components	**λ (f/yr)**	**r (hours)**	**U (hours/yr)**
132kv bus	0.002	50	0.01
Breaker 1	0.005	50	0.25
Transformer 1	0.01	200	2.0
Breaker 2	0.005	20	0.1
Breaker 3	0.005	50	0.25
Transformer 2	0.01	200	2.0
Breaker 4	0.005	20	0.1
Breaker 5	0.005	20	0.1
33 kv bus2	0.005	20	0.025
Breaker 6	0.005	20	0.1
Line	0.05	5	0.025
Breaker 7	0.005	20	0.1
Total	**0.117**	**43.25hrs**	**5.06**

Table 4.6 (c) Reliability Data for Generators (Source: Billinton, 1995).

Size (MW)	Type	No of Units	Forced Outage	Failure Rate	Repair Rate per year
5	Hydro	2	0.010	2.0	198
10	Thermal	1	0.020	4.0	196
20	Hydro	4	0.015	2.4	157
20	Thermal	1	0.025	5.0	195
40	Hydro	1	0.020	3.0	147
40	Thermal	2	0.030	6.0	194

Table 4.6 (d) Annual Percentage Outage Time of the Load Points

	Load Points	Existing Load	Scenario 1	Scenario 2	Scenario 3
1	VOI	1.06	1.06	1.06	1.06
2	RABAI	1.26	2.22	2.22	2.22
3	ARM	0.49	2.18	2.18	2.18
4	MIRITINI	0.16	2.07	2.07	2.07
5	SCI	0.08	1.06	1.06	1.06
6	KILIFI	1.06	1.06	1.06	1.06
7	KIKAMBALA	0.09	0.09	0.09	0.09
8	NEW BAMBURI	1.06	1.06	1.06	1.06
9	SHANZU	0.24	0.24	0.24	0.24
10	KIPEVU	1.31	1.31	2.20	2.20
11	MAKANDE	0.81	0.81	2.18	2.18
12	MALINDI	0.08	0.08	1.06	1.06
13	TAVETA	-	-	-	1.06

The reliability criteria assumed is Loss of Load Expectation (LOLE) of 4 days/year which represents 1.1 % annual outage time of the load points [LCPDP 2009] .Table 4.6(d) show that Rabai, ARM, Miritini ,Kipevu and Makande load points experience reliability problems in some of the scenarios. The options that may address this problem are;

- E_1 - Introducing a 30MW Distributed Generator at Kikambala Substation.
- E_2 - Separate the load at Kipevu by Upgrading Makande Substation from 33/11kv,2.5MVA to 132/33kv,23MVA Substation
- E_3 - Separate the load at Rabai by upgrading the Miritini Substation from 33/11k V, 10MVA to 132/33k V,30 MVA Substation.

4.4.2 Evaluation of Annual Energy Losses

In this research project only the real power losses associated with each solution will be considered, based on the 33k V line. The energy losses are calculated from I^2 RT, the conductor used is Mulberry 150.9mm^2 over head line cable with a line impedance of 0.2648Ω/k M.The assumption made is that there are no losses in the cables between the hv and the lv side of the transformer and the bus bars. Table 4.7 shows the calculated annual energy losses for all the load points.

The percentage annual energy loss is determined by;

$$\frac{\textit{The options reduction in energy losses}}{\textit{Total energy losses in that scenario}} \times 100$$

Table 4.7 Annual Energy Losses in MWh

#	Distribution Lines	Existing Load	Scenario 1	Scenario 2	Scenario 3
1	RABAI – ARM	169.10	285.78	488.71	676.41
2	RABAI - MIRITINI	1313.00	2218.95	3794.54	5251.96
3	RABAI –SCI	3584.04	-	-	-
4	KILIFI – KIKAMBALA	180.38	304.84	521.29	721.50
5	KILIFI - MALINDI	18186.04	30734.41	-	-
6	NEW BAMBURI – SHANZU	338.48	572.04	978.21	1353.93
7	KIPEVU – MAKANDE	188.47	318.52	544.68	753.88
8	VOI –TAVETA	464.23	784.56	1341.64	1856.95
	TOTAL	**17149.32**	**35219.10**	**7669.07**	**10614.63**

4.4.3 Environmental Impact Evaluation

The methodology adopted for this criterion is to consider the total circuit length of new or modified network circuit. For each new or modified circuit, the length is weighted to represent the likely environmental impact associated with the visual obstruction and implementation of each circuit type and route. This weighted length is then summed over all new or modified circuits to determine a weighted value for each planning solution [Espie, 2003].

The approximate total length of the 33k V distribution line being considered in this region is presently 201.9km [KPLC, 2009].

According to the envisaged development on the network in the next 20yrs, most of the 33/11k V substations are going to be replaced by the 132/33 kV Grid substation hence resulting to a reduction in the length of the 33k V overhead lines. Therefore considering only the impact of the 33k V lines on the environment, it shows that the weighted average length will reduce to 153.8km, 89.8k M in and 62.1k M in scenario 1, 2 and 3 respectively. The percentage in reduction is also 76.17%, 44.48% and 30.76% respectively.

4.5 Evaluation of Alternatives Solution

The evaluation process adopted in this research project is the analytical hierarchy process (AHP) which has many similarities to the simple multi-attribute rating technique value function approach [Belton and Stewart, 2002].

The major characteristic of the AHP method is the use of pair wise comparisons, which are used both to compare the alternatives with respect to the various criteria and estimate criteria with the desirability score Table 2.1 in chapter 2 showed the intensity of preference values used to generate table 4.8.

In table 4.8 each of the four criteria has been assigned desirability score based on the intensity of preference value. There are two sets of value associated with these criteria. The first set is the relative score, which is embedded in the design process and present accepted performance record. The second set called user preference weights represents the users concerns and circumstances and is thus somewhat subjective. Relative scores represent a quantitative evaluation of a design alternative or system component with respect to each of the considered criteria.

These scores are defined through an extensive consultation process where several experts in the field give their judgments. To ensure that the planning solutions recommended are indeed robust, sensitivity analysis can be performed in the initial criteria weight values. This sensitivity analysis can take the form of an *ad hoc* assessment where random or logical variations on the criteria weight values are assessed. Alternatively, the sensitivity of the criteria weight values can be evaluated by developing an importance rank order for the evaluation criteria. The rank- order should be easier to determine than the specific weight values, since no indication is needed of the magnitude of change. Equations are developed to represent the feasible region of criterion weight values which are then analyzed to identify the most extreme points of the feasible region. By performing the MCDM analysis using the weight values identified from the extreme feasible region points, the desirability score for each solution for these extreme points can be identified. The recommended planning solution(s) identified from the initial criteria weight values can be compared with the results of the extreme criteria weight region to determine the sensitivity of these desirability scores to extreme variations in criteria weight values [Belton and Stewart 2002].

Once defined; these scores cannot be altered by the user. User preference weights allow the designer to stress some criteria over others. For example, some utilities may be forced to stress cost very heavily over others because of very limited resources while other utilities may prefer more reliable designs.

It can be noted that relative score representing performance may assume slightly different values depending on the experts involved in their choice but this disparity is not substantial. On the other hand, the user preference weights may differ widely from one user to another depending on the prevailing conditions under which the network is being designed [Atanackovic et al, 1998].

Table 4.8 pair wise comparison of desirability Scores (Source: Saaty 1996)

Capacity Constraint		**Reliability**		**Annual Energy losses**		**Environmental impact**	
Criteria % Value	Desirability Score	Criteria % Value	Desirability Score	Criteria % Value	Desirability Score	Criteria % Value	Desirability Score
≥ 100	1	≥ 1.1	1	≥ 100	1	≥ 100	1
80 - 99	3	1.1 - 0.8	3	80 - 99	3	80 - 99	3
70 - 79	5	0.79 - 0.60	5	70 - 79	5	70 - 79	5
60 - 69	7	0.59 - 0.50	7	60 - 69	7	60 - 69	7
50 - 59	9	0.49 - 0.40	9	50 - 59	9	50 - 59	9
≤ 50	10	≤ 0.39	10	≤ 50	10	≤ 50	10

In table 4.8 capacity constraints are assigned desirability scores depending on the percentage loading on each load point or substation. The less a transformer or a line is loaded the higher the desirability score.

Reliability desirability score is based on the loss of load expectation (LOLE) of 1.1.As a result the closer the load point's LOLE is to 1.1 the less it scores and vice-versa.

Annual energy losses and environmental impact follow a similar pattern in that the less the percentage power losses on the line and percentage visual obstruction respectively the higher the desirability score assigned. Table 4.8 is based on the intensity of preference table 2.1.

4.6 Generation of Data for each Solution Configuration

Table 4.5 showed the identified 72 alternative solution configurations for the test distribution network. The solutions option sets are A_1A_2, $B_1B_2B_3$, C_1C_2, D_1D_2, and $E_1E_2E_3$.Giving option combination as follows;

A_1B_1 [2*2*3] = 12 Solutions A_2B_1 [2*2*3] = 12 Solutions

A_1B_2 [2*2*3] = 12 Solutions A_2B_2 [2*2*3] = 12 Solutions

A_1B_3 [2*2*3] = 12 Solutions A_2B_3 [2*2*3] = 12 Solutions

Where [2*2*3] represents the multiplication of C, D and E option sets, e.g. the 1st solution is the combination of five options from each class i.e. A_1B_1 C_1 D_1 E_1, and the 72nd which is the last solution is A_2B_3 C_2 D_2. E_3.

The MCDM technique used is the simple Multi-attribute Rating Technique (SMART).

The desirability of each alternative solution is determined by calculating a decision score in each criterion and multiplying this by the weight value assigned to that criterion by the distribution system planner (see table 4.9). The total decision score for each alternative is then determined using linear additive –value function to sum the individual scores of each criterion [Espie et al 2003, Atanackovic et al, 1997].

The equivalent scores for each of the four criteria having been determined, the overall evaluation of the alternative solution is found using the following expression;

$$SCORE_{TOT} = W_{CC}*SCORE_{CC} + W_{REL} * SCORE_{REL} + W_{AEL} * SCORE_{AEL} + W_{ENV} * SCORE_{ENV}$$

Where W_{CC}, W_{REL}, W_{AEL} and W_{ENV} are user preference weights and $SCORE_{TOT}$ is the overall desirability score for the alternative solution.

It is important to note that the consideration of evaluation criterion weight values is the most contentious issue associated with the application of MCDM techniques as the chosen weight value will have direct impact on the resulting solution desirability scores.

In this research project it is assumed that the set weight values being used in the MCDM analysis have been identified through a structured knowledge capture with planning engineers and other stakeholders to arrive at a consensus through discussion. Dedicated techniques are available for this purpose to elicit weight values from individuals, teams and organizations [Belton and Stewart, 2002] but that is out of the scope of this research project. Table 4.9 shows the evaluation criteria weights for the distribution network used. Since loss of capacity or curtailed demand is heavily penalized, each solution that incurs some loss of capacity receives a substantial reduction in desirability score. Although Capital cost has no MCDM weight value, it will be included in the planning decision process by comparing both the capital cost and generated desirability score of each planning solution in the later chapter. The next section demonstrates a typical process of determining the desirability score for one of the alternatives solutions in scenario one.

Table 4.9 Evaluation criteria weights for test distribution network

Criterion	**Weight Value**
Capacity Constraints	9
Reliability	5
Annual Energy Losses	6
Environmental Impact	8

Option A_1

Option A_1 is to upgrade Kilifi Tx 1 and Tx 2 from 15MVA to 23MVA and 23MVA to 30MVA which results to 95.15% and 95.24% loading respectively, the solution is worked out as follows;

- Capacity constraint for option A_1 is 95.24% giving a decision score of 3 and the weight value W_{CC} for capacity constraint is given as 9 (see tables 4.7, 4.8 (b) & 4.9) hence a decision score of $SCORE_{CC} = 3*9 = 27$
- Similarly percentage Reliability is 1.06% giving a decision Score of 3 and the weight Value W_{REL} of 5 hence $SCORE_{REL} = 3*5= 15$.
- Percentage annual Energy losses is assumed to be 100 % since option A_1 does not give any reduction in energy losses giving a decision score of 1 and weight value W_{AEL} of 6 hence $SCORE_{AEL} = 1*6 = 6$.
- Percentage Environmental impact is 100% since option A_1 does not contribute to the reduction on environmental impact giving a decision score of 1and the weight value W_{ENV} of 8 hence $SCORE_{ENV} = 1*8 = 8$.

  Therefore the total score for option A_1, $SCORE_{TOT} = 27+15+6+8 = 56$ out of the possible score of $(9*10) + (5*10) + (6*10) + (8*10) = 280$.

Notice that option $A_1= B_1= C_1= D_1$.

Option A_2

Option A_2 is reducing the load at Kilifi substation by upgrading the Malindi Substation from a 33/11kv, 7.5MVA to a 132/33kv, 23MVA Substation and is determined as follows;

- Capacity constraint for option A_2 is 58.74% giving a decision score of 9 and the weight value W_{CC} for capacity constraint is given as 9 (see tables 4.7, 4.8 (b) & 4.9) hence $SCORE_{CC} = 9*9 = 81$
- Similarly percentage Reliability is 1.06% giving a decision Score of 3 and the weight Value W_{REL} of 5 hence $SCORE_{REL} = 3*5= 15$.
- Percentage annual Energy losses is 12.73% which is < 50 % giving a decision score of 10 and weight value W_{AEL} of 6 hence $SCORE_{AEL} = 10*6 = 60$.
- Percentage Environmental impact is 41.60% giving a decision score of 7 and the weight value W_{ENV} of 8 hence $SCORE_{ENV} = 10*8 = 80$

Therefore the total score for option A_1, $SCORE_{TOT} = 81+15+60+80 = 236$ out of the possible score of 280. It's worth noting again that $A_2= B_2= C_2= D_2$.

Option B_3

Options B_3 which is to upgrade the capacity of New-Bamburi-Shanzu, 5.7Km line conductor from Mulberry 150.9mm^2 with a resistance of 0.2648 Ω/Km to wolf 156.06mm^2 with a resistance of 0.2233 Ω/Km (see appendix D) results to 94.21% loading gives the following scores;

- Capacity constraint for option B_3 is 94.21% giving a decision score of 3 and the weight value W_{CC} for capacity constraint is given as 9, hence $SCORE_{CC}$ = 3*9 = 27
- Similarly percentage Reliability is 0.24% giving a decision Score of 10 and the weight Value W_{REL} of 5 hence $SCORE_{REL}$ = 10*5= 50.
- Percentage annual Energy losses as a result of change of conductor size are 26.09% giving a decision score of 10 and weight value W_{AEL} of 6. $SCORE_{AEL}$ = 10*6 = 60.
- Percentage Environmental impact is 100% since option B_3 does not contribute to reduction on environmental impact which is dependent on the weighted circuit length therefore giving a decision score of 1 and the weight value W_{ENV} of 8 hence $SCORE_{ENV}$ = 1*8 = 8.

  Therefore the total score for option A_1, $SCORE_{TOT}$ = 27+50+60+8 = 145 out of the possible score of 280.

Option E_l

Options E_l is to locate a 30MW DG at Kikambala Substation and that gives the following scores;

- Capacity constraint for option E_l with a loading of 58.17% gives a decision score of 9 and the weight value W_{CC} for capacity constraint is given as 9, hence $SCORE_{CC} = 9*9 = 81$
- Similarly percentage Reliability is 0.39% giving a decision Score of 10 and the weight Value W_{REL} of 5 hence $SCORE_{REL} = 10*5= 50$.
- Percentage annual Energy losses reduction assumed to be 100% since option E_l does not result in any reduction in energy losses therefore giving a decision score of 1 and weight value W_{AEL} of 6 hence ,$SCORE_{AEL} = 1*6 = 6$.
- Percentage Environmental impact is 100% since option E_l does not contribute to reduction on environmental impact which is dependent on the weighted circuit length therefore giving a decision score of 1and the weight value W_{ENV} of 8 hence $SCORE_{ENV} = 1*8 = 8$.

  Therefore the total score for option $A_{l,}$ $SCORE_{TOT} = 81+50+6+8 = 145$ out of the possible score of 280.

Option E_2

Options E_2 is to separate the load at Kipevu by upgrading Makande Substation from a 33/11kv, 2.5MVA to a 132/33kv, 23MVA Substation which gives the following scores;

- Capacity constraint for option E_2 is 54.67% giving a decision score of 9 and the weight value W_{CC} for capacity constraint is given as 9 ,hence

  $SCORE_{CC} = 9*9 = 81$

- Similarly percentage Reliability is 1.06% giving a decision Score of 3 and the weight Value W_{REL} of 5 hence $SCORE_{REL} = 3*5= 15$.

- Percentage annual Energy losses is 99 % giving a decision score of 3 and weight value W_{AEL} of 6 hence $SCORE_{AEL} = 3*6 = 18$.

- Percentage Environmental impact is 84.52% giving a decision score of 3 and the weight value W_{ENV} of 8 hence $SCORE_{ENV} = 3*8 = 24$

  Therefore the total score for option A_1, $SCORE_{TOT} = 81+15+18+24 = 138$ out of the possible score of 280

Option E_3

Options E_3 is to separate the load at Rabai by upgrading Miritini Substation from a 33/11kv, 10MVA to a 132/33kv, 30MVA Substation which gives the following scores;

- Capacity constraint for option E_3 is 47.55% giving a decision score of 10 and the weight value W_{CC} for capacity constraint is given as 9 ,hence

  $SCORE_{CC} = 10*9 = 90$

- Similarly percentage Reliability is 1.06% giving a decision Score of 3 and the weight Value W_{REL} of 5 hence $SCORE_{REL} = 3*5= 15$.

- Percentage annual Energy loss is 93.69 % giving a decision score of 3 and weight value W_{AEL} of 6 hence $SCORE_{AEL} = 3*6 = 18$.
- Percentage Environmental impact is 69% giving a decision score of 7 and the weight value W_{ENV} of 8 hence $SCORE_{ENV} = 7*8 = 56$

  Therefore the total score for option A_1, $SCORE_{TOT} = 90+15+18+56 = 179$ out of the possible score of 280.

Therefore the first solution desirability Score which is a combination of A_1B_1 C_1 D_1 E_1 options may be calculated as follows;

$$\text{Desirability score} = \frac{56+56+56+56+145}{280*5} = 0.26$$

Table 4.10 shows the $SCORE_{TOT}$ for each option which have been used to compute the desirability scores in all the three scenarios.

Table 4.10 Total score for each alternative option

Options	**Scenario 1 $SCORE_{TOT}$**	**Scenario 2 $SCORE_{TOT}$**	**Scenario 3 $SCORE_{TOT}$**
A_1,B_1, C_1,D_1.	56	56	56
A_2,B_2,C_2, D_2.	236	236	236
B_3	145	181	181
E_1	145	145	145
E_2	132	160	160
E_3	179	203	203

4.7 Individual Scenario Results

Table 4.11 (a), (b), &(c) and figure 4.5, 4.6 and 4.7 shows typical desirability scores for each solution for the three scenario and corresponding graphs. It is evidence from the comparison of figure 4.5, 4.6 and 4.7 that the desirability scores for the three load scenarios are broadly similar. However there is a distinctive pattern present in fig 4.6 and 4.7 which is missing from figure 4.5.

The results show that the highest desirability score is solution number 36 in scenario 2 with a score of 0.86 and the lowest desirability score is solution one with a score of 0.26 and its common in all the three scenarios.

Table 4.10 (d) and fig 4.8 shows the weighted average of all the three scenarios and the highest desirability score becomes solution number 60 with a score of 0.81 with an option combination of $A_2B_2C_2D_2E_3$, the lowest still remain solution number one with a score of 0.26 and a combination option of $A_1B_1C_1D_1E_1$. Its worth noting that all the options constituting solution number 60 propose reducing the load of the individual substations by upgrading feeder substation from 33k V to 132/33k V substation. These options seem to be the most prefered. According to this option most of the 33k V lines are replaced by the 132k V grid transmission line. Most of the options in solution 1 advocate for upgrading of individual load capacities of substation transformers (meaning replacing the transformers with the one of higher capacity).These options does not look popular hence has low desirability score.
In addition it is important to bear in mind that a possibility may arise that a solution may be over-specified because some combinations of options could include redundant elements.

Scenario 1

Table 4.11 (a) Desirability scores table for scenario 1 (2012)

Sol	Score	Sol	Score	Sol	Score	Sol	Score	Sol	Score	Sol	Score
1	0.26	13	0.39	25	0.33	37	0.33	49	0.52	61	0.46
2	0.25	14	0.38	26	0.32	38	0.32	50	0.51	62	0.45
3	0.29	15	0.42	27	0.35	39	0.35	51	0.53	63	0.48
4	0.39	16	0.52	28	0.46	40	0.46	52	0.65	64	0.58
5	0.38	17	0.51	29	0.45	41	0.45	53	0.64	65	0.57
6	0.42	`18	0.55	30	0.48	42	0.48	54	0.67	66	0.61
7	0.39	19	0.52	31	0.46	43	0.46	55	0.65	67	0.58
8	0.38	20	0.51	32	0.45	44	0.45	56	0.64	68	0.57
9	0.42	21	0.55	33	0.48	45	0.48	57	0.67	69	0.61
10	0.52	22	0.65	34	0.58	46	0.58	58	0.78	70	0.71
11	0.51	23	0.64	35	0.57	47	0.57	59	0.77	71	0.70
12	0.55	24	0.67	36	0.61	48	0.61	60	0.80	72	0.74

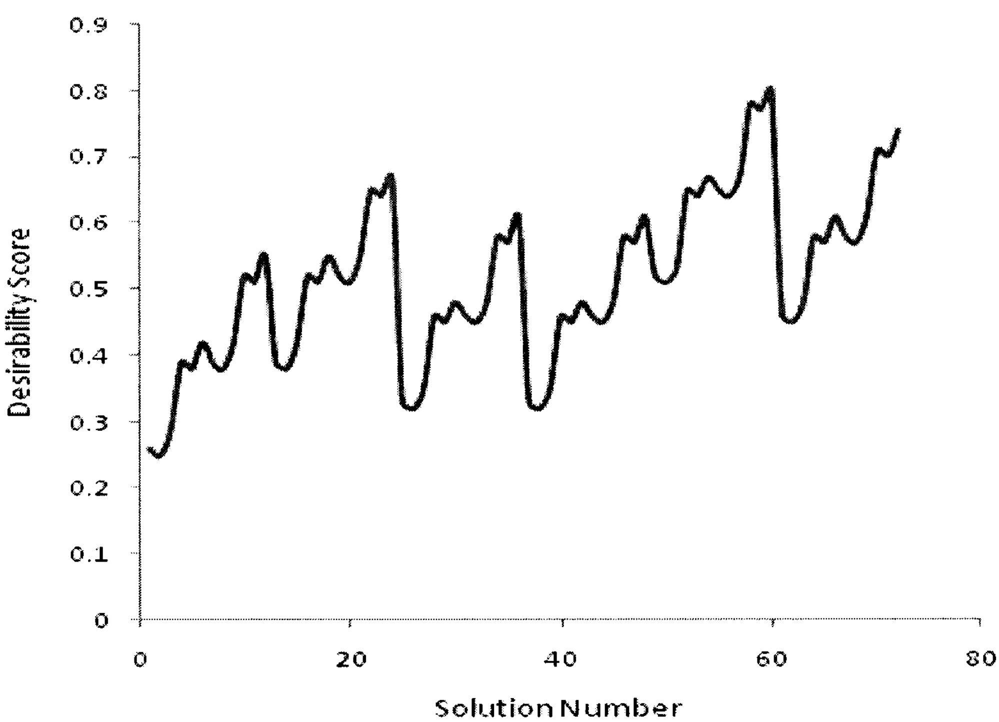

Figure 4.5 Desirability score for scenario 1 (2012)

Scenario 2

Table 4.11 (b) Desirability scores table for scenario 2 (2022)

Sol	Score	Sol	Score	Sol	Score	Sol	Score	Sol	Score	Sol	Score
1	0.26	13	0.39	25	0.35	37	0.39	49	0.52	61	0.48
2	0.27	14	0.40	26	0.36	38	0.40	50	0.53	62	0.49
3	0.31	15	0.43	27	0.39	39	0.43	51	0.56	63	0.52
4	0.47	16	0.52	28	0.48	40	0.52	52	0.65	64	0.61
5	0.48	17	0.53	29	0.49	41	0.53	53	0.66	65	0.62
6	0.51	`18	0.56	30	0.52	42	0.56	54	0.69	66	0.65
7	0.47	19	0.52	31	0.48	43	0.52	55	0.65	67	0.61
8	0.48	20	0.53	32	0.49	44	0.53	56	0.66	68	0.62
9	0.51	21	0.56	33	0.52	45	0.56	57	0.69	69	0.65
10	0.60	22	0.65	34	0.82	46	0.65	58	0.78	70	0.74
11	0.61	23	0.66	35	0.83	47	0.66	59	0.79	71	0.75
12	0.64	24	0.69	36	0.86	48	0.69	60	0.82	72	0.78

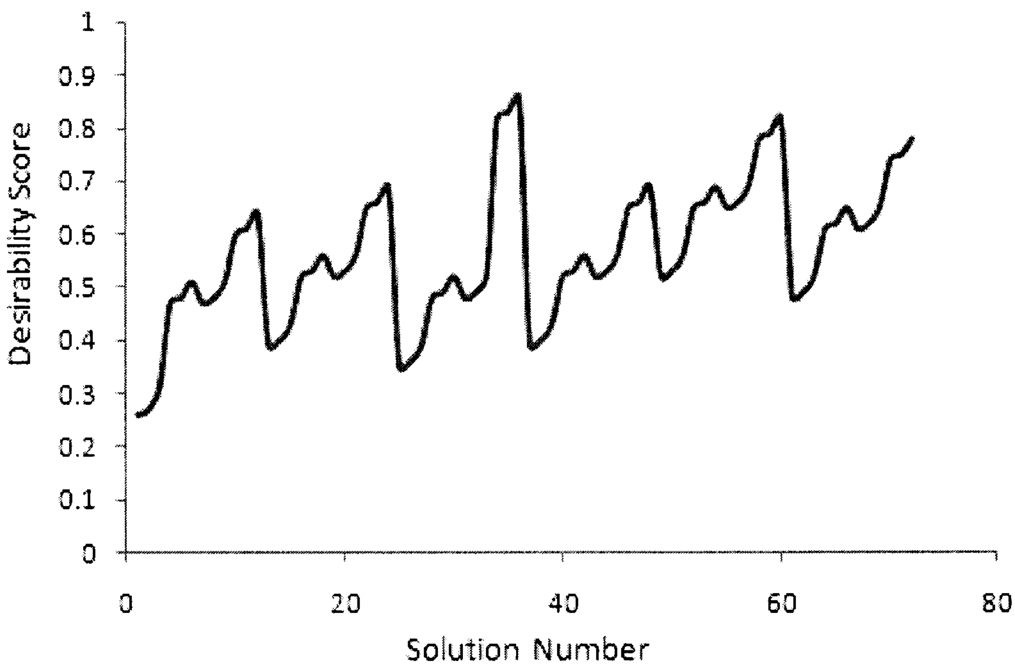

Figure 4.6 Desirability score for scenario 2 (2022)

SCENARIO 3

Table 4.11 (c) desirability scores table for scenario 3 (2030)

Sol	Score	Sol	Score	Sol	Score	Sol	Score	Sol	Score	Sol	Score
1	0.26	13	0.38	25	0.36	37	0.38	49	0.50	61	0.47
2	0.27	14	0.39	26	0.36	38	0.39	50	0.51	62	0.48
3	0.31	15	0.42	27	0.39	39	0.42	51	0.54	63	0.51
4	0.46	16	0.50	28	0.47	40	0.50	52	0.62	64	0.59
5	0.47	17	0.51	29	0.48	41	0.51	53	0.62	65	0.60
6	0.50	`18	0.54	30	0.51	42	0.54	54	0.65	66	0.63
7	0.46	19	0.50	31	0.47	43	0.50	55	0.62	67	0.59
8	0.47	20	051	32	0.48	44	0.51	56	0.62	68	0.60
9	0.50	21	0.54	33	0.51	45	0.54	57	0.65	69	0.63
10	0.59	22	0.62	34	0.59	46	0.62	58	0.73	70	0.70
11	0.60	23	0.62	35	0.60	47	0.62	59	0.74	71	0.71
12	0.63	24	0.65	36	0.63	48	0.65	60	0.77	72	0.74

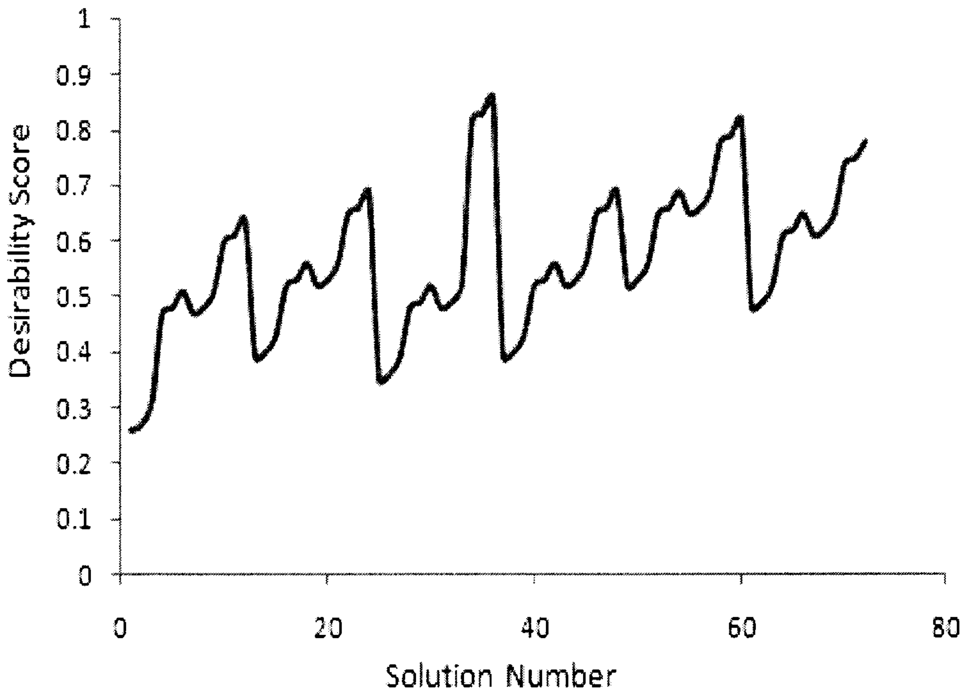

Figure 4.7 Desirability score for scenario 3 (2030)

Weigthted Average

Table 4.11 (d) weighted average desirability score table for the three scenarios

Sol	Score	Sol	Score	Sol	Score	Sol	Score	Sol	Score	Sol	Score
1	0.26	13	0.39	25	0.34	37	0.36	49	0.52	61	0.47
2	0.26	14	0.39	26	0.34	38	0.36	50	0.52	62	0.47
3	0.30	15	0.43	27	0.37	39	0.39	51	0.50	63	0.50
4	0.43	16	0.52	28	0.47	40	0.49	52	0.65	64	0.60
5	0.43	17	0.52	29	0.47	41	0.49	53	0.65	65	0.60
6	0.47	`18	0.56	30	0.50	42	0.52	54	0.68	66	0.63
7	0.43	19	0.52	31	0.47	43	0.49	55	0.65	67	0.60
8	0.43	20	0.52	32	0.47	44	0.49	56	0.65	68	0.60
9	0.47	21	0.56	33	0.50	45	0.52	57	0.68	69	0.63
10	0.56	22	0.65	34	0.70	46	0.62	58	0.78	70	0.73
11	0.56	23	0.65	35	0.70	47	0.62	59	0.78	71	0.73
12	0.60	24	0.68	36	0.74	48	0.65	60	0.81	72	0.76

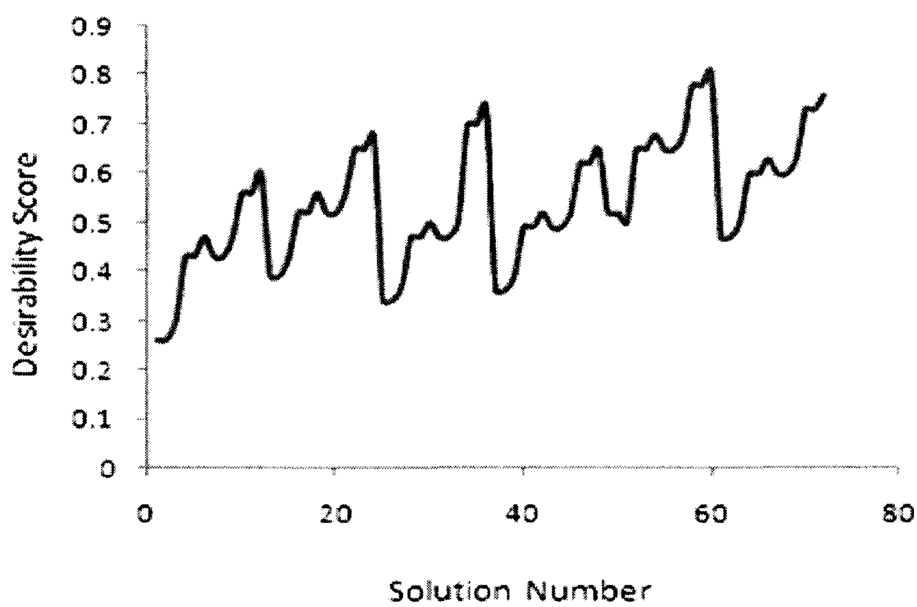

Figure 4.8 weighted average score for the three scenario

4.8 Onward

This case study has shown that evaluating all planning problems simultaneously within the horizon planning period can provide significant insight or microscopic overview of the network. This is a great benefit to the planners in the Kenya power sector, not only in terms of improving the desirability of possible solutions but also by potential deferring network investment until appropriate time. It is interesting to note that Kilifi Substation has been overloaded at peak load in all the three scenarios despite the envisaged planned development being included in the network. This is a clear indication that the planned developments were more focused on the traditional cost optimization planning approaches. This type of planning methodologies does not holistically evaluate the network within the horizon planning period. The proposed methodology being advocated by this research project is actually in contrast with the planning methodology currently being used in Kenya.

The other issue that has emerged clearly in this case study is that the option of upgrading substation from 33/11 k V to 132/33 k V yields high desirability scores. Although the expansion of transmission lines is out of the scope of this project, the option seems to be more preferred since the power carriage capacity is increased hence more consumers can be reached.

A key benefit of this approach is the ability to make strategic planning decisions relating to both the whole distribution network and also particular individual planning problems, resulting in a flexible and robust plan.

CHAPTER FIVE: EVALUATION OF ELECTRICITY DISTRIBUTION SYSTEM COSTING

5.1 Introduction

The optimization of capital expenditure is an important consideration for an electricity distribution utility, if it is to remain competitive in an ever demanding market. In order that capital expenditure can be optimized it is important that a thorough evaluation of the distribution system costing be done. Traditionally, typical investment decisions problem require both economic and technical data to be considered this chapter discusses distribution costing evaluation that include both attributes.

5.2 Electricity Distribution Expansion Investment Plan in Kenya

Referring to chapter two we saw that the envisaged strategy for the distribution expansion plan captured in the "Kenya vision 2030" plan is the construction of an additional approximately 16,000k M of MV distribution lines,1,000MVA of distribution substations,50,000k M of LV distribution lines,3,000MVA of distribution transformers and additional one million service lines [Vision Secretariat Report 2009].

The project is to cover the following key areas:

i) Upgrade of the existing and construction of new substations;

ii) Extension and reinforcement of the distribution network;

iii) Upgrade of Supervisory control and Data Acquisition/Energy Management System (SCADA/EMS).

iv) Initiation of new distribution lines and substations to further extend power supply in rural areas.

These projects are to be developed by Kenya Power and Lighting Company (KPLC) and Rural Electrification Authority (REA) with construction work to be shared between KPLC, Turnkey Contractors and Labour and Transport Contractors [LCPDP, 2009].

5.2.1 Existing Transmission and Distribution Network

Kenya's existing transmission network consists of 220 and 132k V high voltage transmission line, and the distribution network consists of 33 and 11kV medium-voltage lines, as well as 66kV feeder lines within Nairobi the Capital city.

Table 5.1 shows the lengths of KPLC grid and distribution lines based on digital data last updated in October 2007.

Table 5.1 Length of transmission and distribution lines in Kenya (Source: CEI, 2007)

Transmission and Distribution Lines	**Estimated length based on KPLC Annual Report 2006/07 (km)**	**Estimated length based on KPLC Digitized data 2006/07 (km)**
220kv existing	1,323	1,355
132kv existing	2,122	1,726
66kv existing	632	607
33kv existing	11,163	9,040
33kv under construction	-	3,369
11kv existing	21,918	10,090
11kv under construction	-	3,307
Total existing MV(33KV+11)	**39,757**	**25,806**
Total proposed MV (El 5years)		41,197
Total KPLC existing + El proposed MV		**67,003**

It is worth noting that the 33k Vand 11kV data on grid line under construction were digitized by the Ministry of energy as part of the 1996/97 Rural Electrification Master Plan. Most of the lines proposed in the REMP have been built, however some proposed 33kV lines may have been built as 11k V and vice versa, and exact location and lengths of these lines may have changed.

5.2.2 Coast Region Electricity Distribution Investment Plan

In Kenya 94% of the households are located in sub locations that fall within the grid Compatible area. This area is concentrated around the cities of Nairobi and Mombasa, and in central, Western and Nyanza Provinces. The total number of house hold connections in Coast Province is 737,805 with an expected new grid connection of 93,035 in the 5year program i.e. (2008-2010) [CEI 2007].

According to the LCPDP [2009] report and Vision 2030 Secretariat [2008] Strategic Plan the distribution investment plan for the coast region up to 2030 is shown in table 5.2.

Table 5.2 Proposed Energy scale –up plan for the Coast region

Project	Description/scope
Rabai –Diani 132kv transmission line	50Km of single circuit 132k V transmission line between Rabai Substation and Galu in Diani, including a 132k V bay at Rabai substation.
Upgrading Diani Substation	Constructing a 132/33k V, 23MVA Substation at Galu Diani.
Rabai-Bamburi-Kilifi 132kv line	Re-construction of the existing 60kM of 132k V single circuit transmission line between Rabai and Kilifi on self – supporting steel lattice towers, instead of the existing wooden poles.
Upgrading Malindi Substation	Constructing a 132/33k V, 23MVA Substation at Malindi North coast.
Voi – Taveta 132kv line	110kM of 132kV single circuit transmission line, and establishing of a 132kV line bay at Voi Substation.
Upgrading Taveta Substation	Constructing a 132/33kV, 5MVA Sub-station at Taveta.
Rabai Diesel plant	Installation of 90MW Diesel plant at Rabai
Kipevu Gas turbine plant	Installation of 70MW Gas turbine at Kipevu

It is evident from table 5.2 that most of the proposed scale up programme targets the transmission line and generation. This means that most of the 33/11k V substations are to be upgraded to 132/33k V substations. As a result some of the 33k V lines are replaced by the 132k V grid transmission line or are used as low voltage feeders from the 132/33k V substations. The two proposed local generators at Rabai and Kipevu are meant for peak loads or peaking generators.

5.3 Overview of Distribution System Costing

According to Gaunt [1988] distribution system cost does not vary linearly with the capacity of components. The economies of scale of one type of equipment are offset by the increased expenditure needed for associated component. For example, if larger distribution transformers are used the low voltage cables become longer and heavier. Component sizing attempt to optimize the cost of the whole system. The preliminary network design may be modified as the design details are developed, to reduce the cost of the system. The lifetime cost should be taken into account by capitalizing the cost of losses. This may lead to a choice of equipment rating larger than needed to meet the thermal and voltage constraints.

Its worth noting that the load for which the network is to be designed has a major influence on the cost of the network. Therefore it is important neither to overestimate the loads, resulting in over-capitalization, nor to underestimate them and incur higher operating and reinforcement costs.

The distribution line cost is primarily due to the cost of three most significant materials, namely the poles, structures, insulators and conductors. Figure 5.1 shows the typical capital cost structure of high voltage distribution lines. An allowance is usually made for planting the poles to depth, and the rest of the cost would cover for overheads, labour, transport etc. The cost of poles, cross arms, insulator and planting depth constitute the line structure cost.

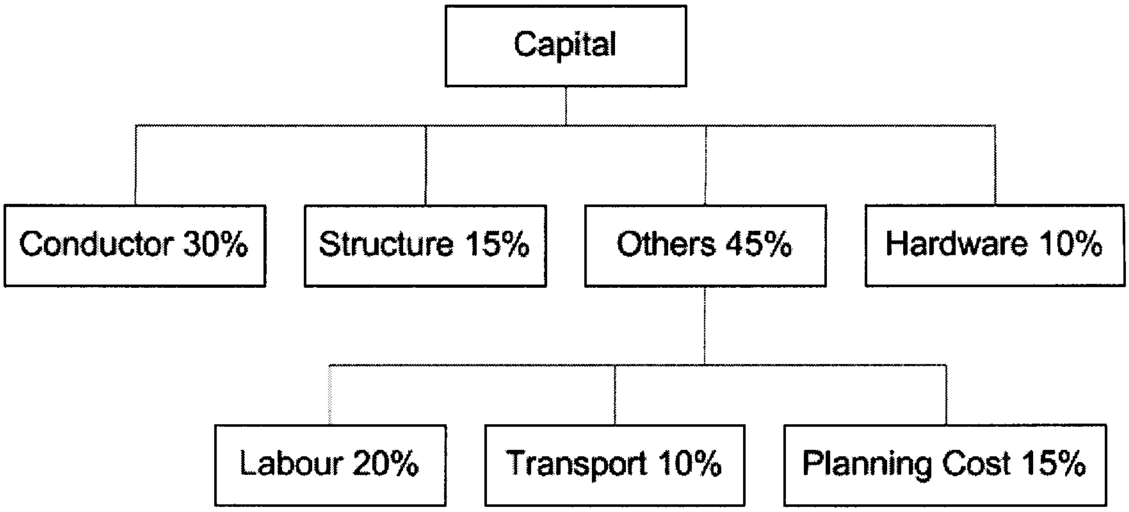

Figure 5.1 Capital cost structure of HV distribution lines [Source: Eskom 1996]

5.4 Costing Methodology for the Distribution Network

According to the Energy and Environmental Economics [2000] report, there are three main methodology issues related to distribution costing i.e.

- Calculation of project cost
- Calculation of marginal cost
- Prioritization and project selection

Figure 5.2 illustrates in more detail the process steps for developing distribution system expansion plan. Typically, most practice potentially misses marginal cost –saving opportunities by not identifying area and time specific marginal costs, and by failing to evaluate alternatives to the base case plan.

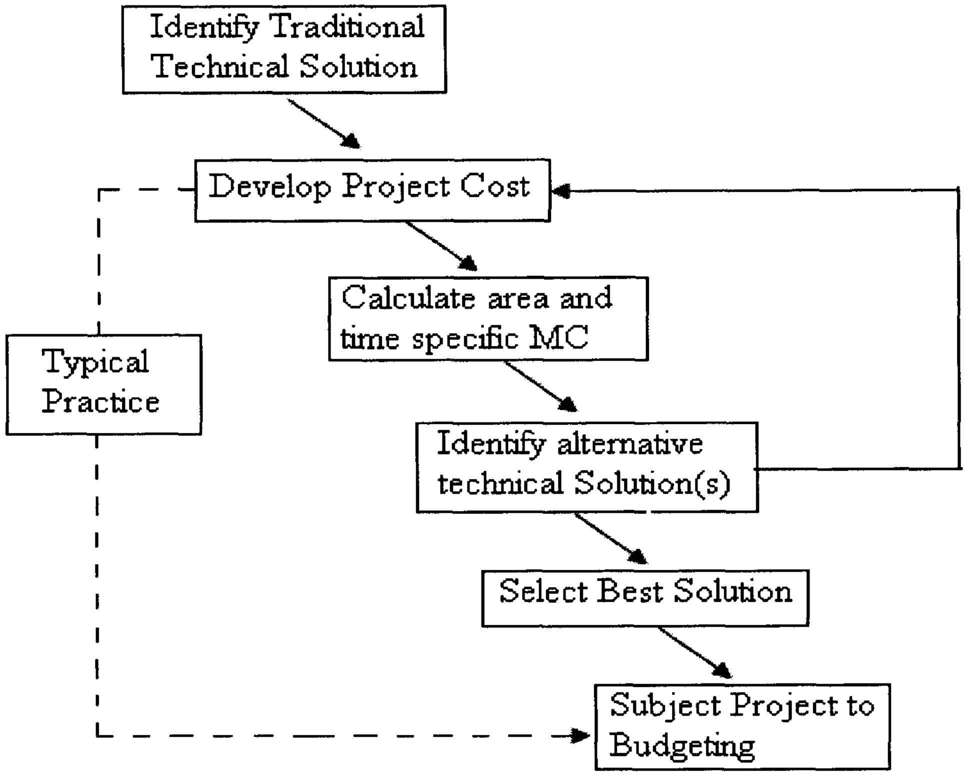

Figure 5.2 Costing steps in distribution expansion plan development [Karl et al, 2000].

Developing Project Costs

The two key cost concepts relevant for distribution system planning are *Project cost* and *marginal cost* .These are not different costs, but different modes of comparison [Khatib 1996]. Project costs are measured in dollars. Traditionally, this includes all direct costs required to meet demand at a specified level of reliability. The least cost alternative(s) for each problem area is usually selected as the base case "best" plan.

Developing project cost is the first step after the technical solutions are identified. Cost estimates can be based on either historical or forward - looking costs. Historical costs can provide a gauge for possible future costs.

However distribution costs are site specific, and engineering estimates of what actually must be done to affect each solution are more accurate projection of the future costs.

Changes of demand can alter what constitutes the best expansion plan looking forward, and therefore project cost estimates should be forward looking. Representative costs data for typical distribution system hardware are provided for reference in table 5.3.

It is important to note that the Kenya equivalent cost for the typical costs listed in table 5.3 would have been the most appropriate for this study but they were not available during the data collection. Therefore both the costs of table 5.3 and some personal data collected during a transformer manufacturing visit mentioned earlier in section 5.2.4 has been assumed.

The essence here is to give the planners a feel of the distribution costing and it's implication on electricity distribution system planning but not necessarily the actual cost which normally would involve experts outside the engineering field.

Table 5.3 Typical Distribution System Hardware costs [Source: Karl et al, 2000].

EQUIPMENT	LOWER COST EXAMPLE	HIGHER COST EXAMPLE
Lines	50k$/mile: 46 k V wooden pole sub transmission	100k$/mile:500 k V double circuit construction with 2,000MVA capacity ($50/kva-mile)
Feeders	Overhead: $10-15 per kW – mile, Rule of thumb for 3-phase overhead wooden –pole cross arm type feeder of normal large conductor (about 600MCM per phase at -12.47 k V) runs about $150,000 per mile. Range is $55,000 to $500,000 per mile.	Underground: $30-50 per kW-mile
Laterals	Overhead: $5-15 per kW-mile	Underground: $5-15per kW-mile (direct buried) $30-100 per kW-mile (ducted)
Substation	Rural substation: 69 k V feed to 5MVA transformer serving 4MW load: approx $90,000 (include all fuses and poles and bus works) or approx $23/kW.	Sub- urban/Urban substation: 2*138 k V lines feeding 2*40MVA 138kV/12.47 kv transformers each with 4*9 MVA feeders for approx $2,000,000. Serving a peak load of about 60MVA this is $33/kW. If serving a tighter

		utilization, could be about $25/kW
Miscellaneous	Mainline, conduit - $90/ft Mainline, DB - $38/ft Lateral, conduit - $63/ft Install transformer - $2,698/ft Change out transformer - $2,822/ft Install -3 switch - $20,871/ft Replace -3 switch - $11,203/ft Install -1 fuse switch - $11,376/ft	Replacing Cable : 1 - $180/ft 3 - $ 360/ft Capacitor (Installed) Substation:$9/KVAR Line $5.5/KVAR Padmounted: $21/KVAR
Connection	Connection cost per customer approx $300 (or $60/kW of coincident load)	
Three – phase pad mounted transformers (installed)	<u>12.5kv (loop feed)</u> 500kva $13,608 750kva $21,357 1000kva $25,515	<u>34.5kv (loop feed)</u> 500kva $20,034 750kva $21,377 1000kva $28,350 1500kva $40,824 2500kva $50,841

Note: The above costs include necessary cable terminations, pads miscellaneous, materials and transformer, but no primary or secondary cables.

Derive Marginal Costs

Marginal costs ($/kw) reflect the change in cost associated with a change in demand. They are derived from least cost "base case" expansion plan determined from the project costs. Marginal costs are used by planners to compare new alternative solutions to the base case investment plan on a more comparable basis: alternative solutions with lower marginal cost would improve the cost-effectiveness of the investment plan.

Both total project cost and marginal costs can vary significantly according to where and when capacity is added. Hence, good costing methodologies will allocate costs by location and time [Karl et al, 2000]. Planning and costing is an iterative process. The starting point is to move through the planning process once using a base case design development from experience and engineering judgment.

After the base case is developed, planners then develop alternative solutions, which are compared to the base case plan in subsequent iterations of costing process. The purpose of deriving marginal costs for planning is to reflect as accurately as possible the incremental costs of investments in distribution system capacity associated with changes in demand. Marginal costs offer a comparable basis on which to evaluate alternative investment that may have different total project costs. There are several methods that can be applied to calculate marginal capacity costs. For distribution costing the present worth method (PW) reflects a good estimate of forward –looking marginal costs against which new alternatives can be compared, and it's straight forward to compute [Khatib, 1996].

The PW method estimates marginal cost by the opportunity cost of the planned capital expenditures from a permanent increase in load. This cost is reflected in the savings associated with shifting the system expansion plan cost stream into the future, sometimes referred to as deferral value. The PW method yields a marginal cost (MC) estimate that varies over time, reflecting the greater marginal costs when investment is imminent.

$$MC_{PW} = CRF^* \frac{\sum_{t=1}^{N} \frac{I_t}{(1+r)^t} - \sum_{t=1}^{N} \frac{I_t}{(1+r)^{t+\Delta t}}}{\Delta L} = \frac{\sum_{t=1}^{N} \frac{I_t}{(1+r)^t} \left[1 - \frac{1}{1+r}\right]^{\Delta t}}{\Delta L}$$

Where;

I_t = Capital investment in year t

Δt = incremental change in peak load divided by the estimated annual change in peak load

ΔL = incremental change in peak load

r = real discount rate

N = number of years in the planning horizon

CRF = Capital Recovery Factor

Prioritization and selection of solutions will be discussed in detail in the next chapter after all the alternative solutions have been computed.

The next sections show the process used to determine the costs of each Solution/options. Note that each alternative solution is formed by a number of options from each option set e.g. Solution one is given as A_1B_1 C_1 D_1 E_1.

5.4.1 Identification of Traditional Technical Solution/Options

The first step in distribution costing is to identify traditional technical solution to the highlighted network problems within the planning horizon period.

In chapter four we identified a number of simulated solution/options that could address the different problems as follows;

- Option A_1 is upgrading Kilifi Tx 1 and Tx 2 from 15MVA to 23MVA and 23MVA to 30MVA which results to 95.15% and 95.24% loading and it's the same as option B_1.
- Option C_1 is upgrading Kilifi Tx 1 from 23MVA to 30MVA and Maintain Tx 2 at 30MVA.
- Option D_1 – is upgrading Kilifi Substation Tx 1 from 30MVA to 60MVA and Tx 2 from 30MVA to 60MVA results to 94.17% and 93.34% loading respectively
- Option A_2 is reducing the load at Kilifi substation by upgrading the Malindi Substation from a 33/11kv, 7.5MVA to a 132/33kv, 23MVA Substation.
- B_2 - Reduce the load at Kilifi substation by upgrading the Malindi Substation from a 33kv/11kv, 7.5MVA to 132/33kv, 23MVA Substation.
- C_2 - Reduce the load at Voi substation by upgrading the Taveta Substation from 33/11kv, 2.5MVA to 132/33kv, 23MVA Substation.
- D_2 - upgrade Kikambala substation from 33/11kv, 2.5MVA to 132/33kv, 23MVA Substation.
- B_3 - upgrade the capacity of New-Bamburi-Shanzu, 5.7Km line conductor from Mulberry 150.9mm^2 with a resistance of 0.2648 Ω/Km to wolf 156.06mm^2 with a resistance of 0.2233 Ω/Km to give 94.21% loading.

- E_1 - Introducing a 2*30MW Distributed Generator at Kikambala Substation.
- E_2 - Separate the load at Kipevu by upgrading Makande Substation from 33/11kv,2.5MVA to 132/33kv,23MVA Substation
- E_3 - Separate the load at Rabai by upgrading the Miritini Substation from 33/11kv, 10MVA to 132/33kv,30MVA Substation.

The costing calculations for the different options are carried out including the assumptions made as follows;

5.4.2 Alternative Solution Costing

Option A_1

The assumptions made in this calculation are based on table 5.3 and the upgrading of the transformers are done at base cost since this option is derived from the existing network condition. Secondly although the distribution system costing does not vary linearly with the capacity of some components the cost of the transformer is multiplied by a factor of 1.6 (Transformer factory visit 2009 revealed that a 1,000kva transformer costs US$46,667 translating to $46.7 per KVA)

The 20MVA – 60MVA are assumed to have a size of 2.5m*1.5m*2.0m, this is because the rating, sizing and costing of transformer from different manufacturers depends largely on the consumers specifications. Therefore for this research project a linear transformer costing has been assumed. Table 5.4 shows a typical costing for option A_1.

Table 5.4 Typical Option / Solution Costing

Requirement/Action	Cost (US $)
23 MVA Transformer	1,074,100
30 MVA Transformer	1,401,000
Install transformer (2,698*1.6*7.5)	32,376
Change out transformer (2,822*1.6*7.5)	33,364
Install 4- switches (27,828*1.6*7.5)	333,936
Replace 4- Switches (14937*1.6*7.5)	179,244
Install 1 fuse switch (11,376*1.6*7.5)	136,512
Total	**3,190,532**

Based on the costing of option A_1 in table 5.4, the costing for option C_1 is $3,517,432 and D_1 is $6,319, 432, but since C_1 and D_1 are projects to be carried out in 2022 and 2030 respectively then present value (discounting) is carried out which captures the erosion of future income by inflation and the existence of risk [Khatib, 1996 and Espie et al, 2000].

The unit cost is given by $(1+i)^n$ where n is the number of years and i is a premium of 10% normally considered for electrical power industry [Khatib 1996] hence B_1 is C_1 is $10,013,326 and D_1 is $42,513,978.

Option A_2

The assumption made based on table 5.3 is that Option A_2 is calculated at base cost. It is a Sub- urban/Urban substation: 2*132kv lines feeding 2*23MVA 132kv/33 kv transformers each with 2*7.5 MVA feeders, Serving a peak load of about 20MVA the cost in table 5.3 is reduced by a factor of 0.67 due to size of equipment being considerer to give a cost of \$33*1.6 *0.67/kw i.e. \$35.38/kw. Hence the total options cost is

\$636,840.Similarly option B_2 (2012) = \$770, option C_2 (2022) = \$1,998,677 and

option D_2= E_2= E_3 (2030) = \$42,843,441

Option B_3

The assumption is that the line cost is given by \$50*1.6*0.1/KVA-mile on a 33Kv wooden pole sub transmission line which total \$338,596.

Option E_1

The Distribution Generators are assumed to be low Speed diesel 2*30MW with a capacity of 60MW at a cost of USCts\$14.23/KWh and commissioning time at 2030 [LCPDP 2009].Therefore the cost is \$41,930,758.The table below shows a summary of the total costs of each option.

Table 5.5 Summary of Option Costs

OPTIONS	TOTAL COST (US$)
A_1	3,190,532
A_2	636,840
B_1	3,860,544
B_2	770,576
B_3	338,596
C_1	10,013,326
C_2	1,998,677
D_1	42,513,978.
D_2	42,843,441
E_1	41,930758
E_2	42,843,441
E_3	42,843,441

Table 5.6 shows the cost for the 72 solutions in millions of US $ and figure 5.3 show the weighted average desirability/$M.

Table 5.6 Solution costs in US$ in millions

Sol	Cost	Sol	Cost	Sol	Cost	Sol	Cost	Sol	Cost	Sol	Cost
1	101.5	13	98.4	25	94.8	37	99.0	49	95.9	61	95.4
2	102.4	14	99.3	26	95.7	38	99.9	50	96.8	62	96.3
3	102.4	15	99.3	27	95.7	39	99.9	51	96.8	63	96.3
4	101.8	16	98.7	28	98.3	40	99.3	52	96.2	64	95.8
5	102.8	17	99.6	29	99.2	41	100.2	53	97.1	65	96.7
6	102.8	18	99.6	30	99.2	42	100.2	54	97.1	66	96.7
7	93.5	19	90.4	31	90.0	43	90.9	55	87.9	67	87.4
8	94.4	20	91.3	32	90.9	44	91.9	56	88.8	68	88.3
9	94.4	21	91.3	33	90.9	45	91.9	57	88.8	69	88.3
10	93.8	22	90.7	34	90.3	46	91.3	58	88.2	70	87.7
11	94.7	23	91.6	35	91.2	47	92.2	59	89.1	71	88.7
12	94.7	24	91.6	36	91.2	48	92.2	60	89.1	72	88.7

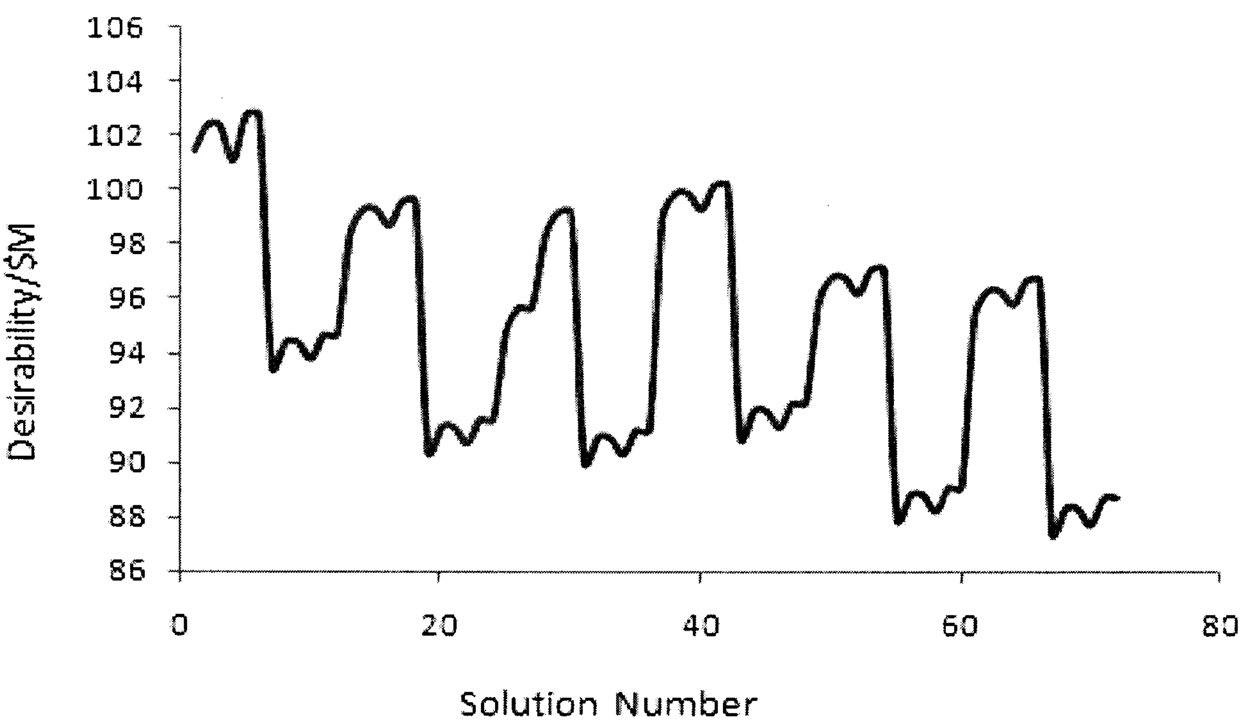

Figure 5.3 Weighted average cost in US$M.

5.4.3 Estimated Cost of Proposed Development on the Network by 2030

Table 5.7 shows the proposed energy scale up plan for the coast region within the horizon planning year 2010-2030 [LCPDP, 2009 and Vision 2030 Secretariat, 2008]. The cost associated with each project has been calculated based on the data in table 5.3 with the same assumptions used when we were working out the costing for various options/solutions configured for the test distribution network.

Table 5.7 Costing for Proposed Energy scale–up plan for the Coast region

Project	**Description/scope**	**Cost in US$**
Rabai –Diani 132k V transmission line (2012)	50kM of single circuit 132k V transmission line between Rabai Substation and Galu in Diani, including a 132kV bay at Rabai substation.	65,709,722
Upgrading Diani Substation (2012)	Constructing a 132/33k V, 23MVA Substation at Galu Diani.	770,576
Rabai-Bamburi-Kilifi 132kV line (2022)	Re-construction of the existing 60kM of 132kV single circuit transmission line between Rabai and Kilifi on self – supporting steel lattice towers, instead of the existing wooden poles.	data not available (Reasonable assumptions to be made)
Upgrading Malindi Substation	Constructing a 132/33kV, 23MVA Substation at Malindi North coast.	1,998,676
Voi – Taveta 132kV line (2030)	110kM of 132kV single circuit transmission line, and establishing of a 132kV line bay at Voi Substation.	185,006,249
Upgrading Taveta Substation (2030)	Constructing a 132/33kV, 5MVA Sub-station at Taveta.	42,843,441
Rabai Diesel plant (2012)	Installation of 90MW Diesel plant at Rabai	11,313,264
Kipevu Gas turbine plant (2030)	Installation of 70MW Gas turbine at Kipevu	41,930,758
Total		**349,572,269.**

It is evident that the estimated cost of the proposed energy scale up development plan is more than three times that of the highest proposed solution cost (see table5.6) basing our calculation on the data of table 5.3 and also assuming the commissioning dates indicated on table 5.7.This is as a result of not considering the 132kv transmission upgrade which is out of the scope of this project. The project only considered the upgrading of the substation to 132/33kv.The other assumption made is that the costing of the 70 MW Kipevu gas turbine plant has been equated to the low Speed diesel 2*30MW.This has been done due to lack of data for some specific costing. Hence the estimated cost minus the transmission cost is
US$ 98,856,715.Therefore taking this figure to represent the investment network development budget up to 2030, a flexible and robust solution can be selected from the 72 options that are available after carrying out a trade- off analysis of the alternative solutions.

5.4.4 Most Desirable Solution

The calculated capital investment budget derived from the envisaged network development projects within the planning horizon period of 20 years (2010-2030) is US$98million.

The solution with highest desirability score of 0.82 is solution 60 with a capital cost of US$89.1M, however solution 67 with a desirability score of 0.60 gives us the lowest capital cost of US$87.4M.and has an option combination of $A_2B_3C_2D_1E_1$. (See fig 4).

Consequently solution 67 may appear cost effective but the utility planner needs to carry out a trade-off analysis to determine the most viable solution depending on the objectives of the "Kenya Vision 2030". The main objective should be to select a solution that provides a techno-economic optimization. Once the viable and desirable solution has been determined the "bottom–up" process of planning may be adopted and the distribution requirements worked upward to converge at the national policy objective where its implication may be assessed and decisions made accordingly.

5.5 Onward

In most cases the most economically efficient planning solution will provide the highest availability desirability score for a given cost value and will almost certainly not equate to either the solution with the lowest cost (as desirability will be low) or the solution with highest available desirability (as the capital cost might be high).

If the calculated capital budget of **US$ 98,856,715** is specified for the test distribution network within the planning horizon year (according to vision 2030) then the solution with the highest available desirability score, which is the most desirable solution that can be implemented, is solution 60 with a desirability score of 0.82 and a capital cost of US$89.1Million. However solution number 67 with an average desirability score of 0.60 gives a capital cost of US$87.4.Thus the utility planner has to carry out a trade off analysis to implement either the solution that has the highest desirability (within the given capital budget), i.e. solution 60, or implement the solution that is the most cost effective and provides the best value for money which is solution 67.In the selection of any these two solutions the techno-economic optimization objective should be the focus of the planners.

The next chapter provides a conclusion and recommendation by evaluating how the national policy impacts on the planning of electricity distribution systems in Kenya with regards to the finding of the research project.

CHAPTER SIX: CONCLUSION AND RECOMMENDATION

The research project has demonstrated that the proposed MCDM technique, embedded in a 'bottom–up' approach planning strategy provides significant insight to the utility planners. This enables them to assess easily the impact of the network projects in all the sectors of the economy simultaneously within the planning horizon year. This is an important aspect in planning because it gives provision for project deferments and prioritization depending on the objectives of the national policy. It has further proved the validity of the hypothesis through the evaluation done in the case study by showing that de-coupling of the capital cost as an evaluation criterion and using it only after all the technical benefits have been evaluated results in a more all inclusive plan with a more likely possibility of achieving the Vision 2030 objectives.

6.1 Research Achievements

The basic hypothesis of this thesis stated that;

An empirical assessment of traditional optimization planning approaches used in electricity distribution system in Kenya when subjected to a planning methodology within multiple criteria decision making techniques embedded in a "bottom-up" planning process, allows for better decision making, resulting in a more likely possibility of achieving the "Kenya Vision 2030" objectives.

The research has proved the validity of this hypothesis. The proposed MCDM techniques used have demonstrated and achieved the following;

- Evaluating all planning problems simultaneously as demonstrated by this approach within a horizon planning year provides significant insight and benefit to the planners, e.g. it was observed in the case study in chapter four that the Kilifi load point (Substation) was overloaded at peak demand in all the three scenarios despite the inclusion of the envisaged planned network development. Such revelation becomes very important to the planner and enables him to mitigate the problem early enough in his planning activity resulting in greater financial saving for the utility and avoiding unnecessary power interruptions.

- The other achievement of the approach is the ability to make strategic planning decision relating to the whole distribution network and also particular individual planning problems, this gives an overall insight or a microscopic view of all the network problems as compared to the planned projects within the planning horizon year, hence giving provision for deferrement of some network investments until an appropriate time, therefore enabling the utility to prioritize the network investments within the planning period, offering flexibility in planning.

- Decoupling of the capital cost as one of the criteria ensures that the technical benefit of each alternative solution is not obscured by the associated solution capital cost. In this research project the capital cost of each solution is compared with the capital budget only after all the technical benefits have been evaluated.This results in a robust plan as opposed to the traditional optimization approaches that commonly consider solution with the minimum cost and minimum line losses regardless of other pertinent issues.

- Finally since the electricity distribution networks extend to every geographic location covered by the utility, providing final connection between the utility and the customer, they are considered the most suitable systems to capture localized customer requirements, load demand and growth patterns. Thus this project advocates that an effective planning process should begin from a 'broad' distribution system planning upward i.e. "bottom- up" approach.

6.2 Conclusion

Electricity distribution system infrastructure plays a critical and positive role in social and economic development. The infrastructure interacts with social, economic, and political objective of "Kenya Vision 2030" through multiple and complex processes.

Traditionally, utility planning procedures are primarily based on a 'Top- down' approach where future system developments are determined from the overall system requirements.

In case of power utilities, like in the " Kenya Vision 2030' power investment plans emphasis was given on the Generation and transmission network and location of substations to minimize transmission network costs. Distribution networks have usually been subjected to uncontrolled expansion, under/over utilization and unplanned development. As a result, many technical problems can be seen in the distribution network of many utilities; these include high power losses, inadequate network capacity, poor system reliability, voltage and power quality problems etc.

Distribution networks extend to every geographic location covered by the utility providing final connection between the utility and the customer. They are therefore considered the most suitable system to capture localized customer requirements, demand and growth patterns.

For example, demand growth will be different in different areas; certain areas need high supply reliability etc. Effective planning process therefore begins from distribution system as opposed to Generation and Transmission. Distribution system requirements are worked out in upward direction, from the identification of distribution network reinforcements/expansions, substation augmentation and new substations to meet these distribution requirements, and transmission line development to meet substation requirements, all of which converging on final objectives; meeting the customer needs and techno-economic optimization. This is known as the 'Bottom–up' approach in utility planning.

Therefore National Policy or "Kenya Vision 2030" may impact more positively on electricity distribution system planning when the proposed MCDM technique embedded in a 'Bottom–up' approach is adopted.

It is important to note that all the three assessment studies carried out on the Kenyan power sector gave emphasis on the Generation and Transmission Scale-Up projects, even the national electrification coverage plan carried out by the Columbia earth institute of New York was more concerned with the electricity national scale-up at household and institutional level, focusing more on cost effective connections and technologies regardless of political administrative boundaries. This indicates that adequate distribution system assessment studies still need to be carried out to ensure robust planning, if Vision 2030 objectives are to be achieved holistically.

The research project demonstrated that there are 72 configured solutions that may be used in aiding the decision makers in their quest to select the most cost-effective plan. Although it is important to note that a possibility may arise that a solution may be over-specified because some combinations of options could include redundant elements.

However this is still a clear indication that the MCDM approach proposed gives a broader and sensitive solution/options therefore enhancing flexibility in the distribution planning activity. The following may be concluded in the context of this research project;

- Network planning is a very complex and difficult task. Planning models have evolved from simplistic (linear models) approaches to multiple criteria models. The distribution planning task has challenges but it is further complicated by the uncertainty of certain parameters.

- It is also acknowledged that the MCDM techniques evaluation criterion weight values is the most contentious issue associated with its application since the chosen weight value have a direct impact on the resulting desirability scores. In this research project its assumed that the set of weight values used in the MCDM analysis have been identified through a structured knowledge captured with planning engineers and stakeholders to arrive at a consensus through discussion.

- The distribution costing carried out on this research project focused mainly on substation equipment and distribution lines as per the data in table 5.3.All costs were first considered from the base cost and the marginal cost point of view. Note that the quality impact costs are out of the scope of this Research Project.

- Risk in planning is mainly due to uncertainty in the long term and as a result long term network plans cannot be guaranteed, however uncertainty models based on fuzzy logic can be used to analyze long-term risks with a degree of accuracy.

- As mentioned earlier a 'broad' distribution network planning should precede Generation and Transmission planning and not vice-versa. In other words the outcome of distribution system planning should determine how the Generation and Transmission Scale–up programme should be carried out.

- Finally since success in the implementation of "Kenya Vision 2030" strategy blue print has been recognized by the Kenyan government to be intertwined with the availability of reliable energy, a MCDM technique embedded in a bottom–up planning approach should be embraced by the Kenya power sector.

6.3 Recommendation

Based on the findings and conclusions of the research project, it's worth noting that the focus of MCDM is on supporting or aiding decision making it is not on prescribing how decisions "should" be made, nor is it about describing how decisions are made in the absence of formal support. Zaleny [1982] said;

> *"The decisions unfold through a process of learning, understanding, information processing, assessing and defining the problem and its circumstances. The emphasis must be on the process, not on the act or the outcome of a decision".*

Much of the MCDM literature can be criticized for adopting a stance of "given the problem" i.e. taking as a starting point a well defined set of alternatives and criteria, and focusing on evaluation. It is unlikely that in practice any problem will present itself to an analyst in this form.

It is more likely that the MCDM process will be embedded in wider process of problem structuring and resolution. Therefore it's recommended that when using MCDM technique for electricity distribution planning the following should be adhered to;

(1) A sensitivity and robustness analysis should be carried out to investigate whether preliminary conclusions are robust or if they are sensitive to changes in aspects of the model. Changes may be made to investigate the significance of missing information to explore the effect of a decision maker's uncertainty about their values and priorities or to offer a different perspective on the problem. The analysis should be viewed from three perspective i.e.,

- Technical perspective;- A technical sensitivity analysis will determine when, if any of the input parameters have a critical influence on the overall evaluation-that is where a small change in criteria weight or an alternative score can affect the overall preference order.
- Individual perspective;- This helps the planner(s) by providing a sounding board against which they can test their intuition and understanding of the problem, e.g. do they feel comfortable with the result of the model? If not why not? Have important criteria been overlooked in the analysis?
- Group perspective;- The function of the sensitivity analysis within the group context is to allow the exploration of alternative perspectives on the problem often captured by different sets of criteria weights, this allows the group to look at the decisions from the perspective of an economist, an environmentalists or different industry representatives.

(2) The electrical power industry is highly capital intensive and involves investments of hundreds of millions of dollars.

Therefore this necessitates a thorough study that involves planners, engineers and architects, economists and financial analysts, environmentalists etc. who look into many considerations which may not seem directly related to the project. Their considerations normally called the 'externalities' may involve issues like effect of the project on employment, regional development, environment, balance of payment, technological advancement, prospects for exports etc. Hence the proposed MCDM technique with its wider spectrum of selection from the alternative solutions when embedded in a "bottom–up" approach strategy provides a good starting point for a network project planning assessment.

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APPENDICES

Appendix A: Summary of the load forecast result [Source LCPDP 2009]

FINAL YEAR	LOW FORECAST		REFERENCE FORECAST		HIGH FORECAST	
	Net Energy (GWh)	Net System Peak (MW)	Net Energy (GWh)	Net System Peak (MW)	Net Energy (GWh)	Net System Peak (MW)
2008/09	7,002	1,183	7,032	1,188	7,047	1,190
2009/10	7,794	1,318	7,889	1,334	7,934	1,342
2010/11	8,579	1,452	8,748	1,481	8,826	1,494
2011/12	9,613	1,628	9,687	1,672	9,989	1,693
2012/13	10,486	1,777	10,844	1,838	11,019	1,868
2013/14	11,480	1,947	11,963	2,029	12,202	2,O70
2014/15	12,580	2,134	13,210	2,242	13,526	2,296
2015/16	13,845	2,350	14,648	2,487	15,054	2,557
2016/17	15,280	2,595	16,284	2,767	16,967	2,855
2017/18	16,793	2,853	18,033	3,066	18,672	3,175
2018/19	18,482	3,142	19,996	3,401	20,783	3,536
2019/20	20,346	3,460	22,178	3,774	23,138	3,938
2020/21	22,400	3,811	24,601	4,188	25,763	4,387
2021/22	24,662	4,197	27,289	4,647	28,686	4,887
2022/23	27,114	4,617	30,233	5,151	31,903	5,437
2023/24	29,795	5,075	33,479	5,706	35,467	6,047
2024/25	32,728	5,576	37,062	6,318	39,416	6,722
2025/26	35,936	6,125	41,017	6,995	43,796	7,,471
2026/27	39,449	6,726	45,385	7,742	48,654	8,302
2027/28	43,296	7,383	50,211	8,568	54,046	9,224
2028/29	47,510	8,104	55,544	9,480	60,030	10,248
2029/30	52,128	8,894	61,440	10,489	66,675	11,385

Appendix B: Electricity distribution system objectives of different interest groups [Gaunt 1988]

ASPECTS	SUPPLY AUTHORITY	CONSUMER	PROPERTY DEVELOPER	GENERAL PUBLIC (SOCIETY)
Safety	Comply with regulations at minimum cost and recommend changes where appropriate.	Ensure safety of own installation within own cost constraint	Comply with regulation at minimum cost	Ensure safety of public, consumers and system operators
Quality of supply and reliability	Meet consumer requirements at an acceptable price	Quality to be suitable for application, at an acceptable price.	-	Adopt parameter for equipment and system standardization in national interest
Appearance	-	Personal assessments of appearance may influence desire to locate in area	Appearance shall not detract unduly from the marketability of a development.	Importance of appearance varies widely
Operation and maintenance	Minimize need for (and cost and complexity of) O&M within constraints of safety, reliability and investment objectives.	O & M should not cause undue interruptions of supply	-	-
Fraud and theft of supply	Prevent or detect theft of energy	Honest consumers have no objectives	-	Common law approach to theft.
Flexibility	Provide flexibility for future development at acceptable cost	-	Avoid additional cost unless clearly justified	-
Income	Maximize income to cover costs and provide surplus, within constrains of regulations	Consumer will use electricity to the extent that its price is lower than the benefit	-	Regulate supply authority income to be compatible with national economic objectives

Investment	Minimize the lifetime cost of the system to the authority	Minimize initial cost of supply	Minimize capital investment of the overall development	Use scarce capital to obtain the optimum benefit for the community
Design	Provide system meeting safety and quality of supply objectives at minimum lifetime cost	Obtain acceptable quality of supply at acceptable cost	Minimize investment without detracting from marketability of development	Comply with regulations and socio-economic objectives of society
Management	Operate an efficient trading enterprise. Provide employment, education and training to win acceptance of public and influence groups such as councils	-	Comply with the requirements of the supply authority which will take over system.	Adopt industry structure and organizations which are effective and efficient.

Appendix C: Substation loading at the Coast region in Kenya [KPLC, 2009]

Substations	Loading (Amperes)	Power Factor
Athi-River Mining (ARM)	135	0.85
Miritini	230	0.85
South Coast Interconnector (Diani)	380	0.9
Rabai	645	0.9
Kilifi	360	0.9
Malindi	350	0.9
Kikambala	45	0.9
New Bamburi	290	0.85
Shanzu	160	0.9
Kipevu	1560	0.9
Makande	250	0.9
Voi	85	0.9

Appendix D: Conductor data [Eskom-1996]

Conductor Type	Conducting Area (mm^2)	Conductor cost (R/m)	Conductor Cost (R/Km)	Line Impedance (Ω/Km)
Squirrel	20.98	1.2	1200	1.6709
Acacia	23.79	1.99	1990	1.6652
Gopher	26.25	1.56	1560	1.3356
Fox	36.68	2.07	2070	0.9556
Rabbit	52.66	2.68	2680	0.6629
Mink	63.13	8.15	8150	0.5554
Pine	71.66	4.73	4730	0.5535
Racoon	78.33	4.01	4010	0.4447
Hare	104.98	4.9	4900	0.3339
Oak	118.9	7.77	7770	0.3342
Mulberry	150.9	9.88	9880	0.2648
Wolf	156.06	10.95	10950	0.2233
Hornet	157.62	8.12	8120	0.223
Ash	180.7	12.18	12180	0.2204
Chicade	212.09	11.84	11840	0.417
Bear	264.42	16.36	16860	0.1335
Sycamore	303.2	19.35	19350	0.1318
Butterfly	322.66	13.41	13410	0.109
Goat	324.31	17.51	17510	0.1088
Kingbird	340.96	18.27	18270	0.379
Upas	362..1	23.28	23280	0.1103
Centipede	415.22	13.29	13290	0.0848
Zebra	426.62	12.3	12300	0.0823
Yew	479	30.77	30770	0.0834
Dinosaur	662	32.39	32390	0.0544
Bull	665.36	37.21	37210	0.0408

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